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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

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FEDERAL ENERGY REGULATORY COMMISSION

JAN 30 1998

Ms. Lois D. Cashell
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Dear Ms. Cashell:

The Environmental Protection Agency (EPA) has reviewed the final Environmental Impact Statement (EIS) regarding the licensing of Cushman Hydroelectric Project (FERC Project No. 460) in accordance with our responsibilities under the National Environmental Policy Act (NEPA) and Section 309 of the Clean Air Act. Our comments are presented below.

Project History and Present Conditions

The Cushman Hydropower Project, constructed in 1926, consists of two dams and two powerhouses that deliver power to the City of Tacoma. The Project received only a "minor part license" in 1924 which authorized the inundation of 8.8 acres of federal land in connection with the construction of a dam on the North Fork of the Skokomish River; no other part of the Project was licensed. At the present time, nearly all of the North Fork's flows are diverted via penstocks out of the Skokomish River Basin and directly to Puget Sound, entirely bypassing the remaining eight miles of the North Fork and nine miles of the mainstem. The estimated mean annual flow of the North Fork at the dam before it is diverted is approximately 784 cubic feet per second (cfs).[1] After the diversion, the only flow into the North Fork is a continuous release of 30 cfs from the dam. The FERC has never imposed any mitigation requirements for the Project; the only mitigation of the Project's adverse environmental effects has resulted from requirements imposed by the State of Washington in 1988 that the owner/operator (Tacoma Public Utilities) contribute funds to help offset the costs of operating a fish hatchery and provide the continuous release of 30 cfs to the North Fork.

Fish and Wildlife Agency Recommendations

In making these comments, EPA notes that the Departments of Interior and Commerce have submitted to the FERC a comprehensive set of license terms, conditions, prescriptions and

[1]The FERC EIS estimates that the mean annual flow is 784 cfs; other sources have estimated mean annual flow levels as high as 842 cfs.

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recommendations under Sections 4(e), 18, 10(j) and 10(a) of the Federal Power Act that would minimize the adverse environmental impacts of the proposed license. The FERC is required by federal law to include the Section 4(e) and Section 18 mandatory conditions and fishways prescriptions in any proposed license it issues. See *Escondido Mut. Water Co. v. La Jolla Band of Mission Indians*, 466 U.S. 765 (1984); *Southern California Edison v. FERC*, 116 F.3d 507 (D.C. Cir. 1997); and *Bangor Hydro-Electric Co. v. FERC*, 78 F.3d 659 (D.C. Cir. 1996). However, the FERC staff recommend in the final EIS that the FERC reject the Section 18 prescriptions and are silent on the status of the Section 4(e) mandatory conditions. Moreover, the FERC staff indicate in the final EIS that a number of the Section 10(j) recommendations should be rejected. EPA believes the environmental impacts of the proposed license would be significantly reduced with the adoption of the terms, conditions, prescriptions and recommendations submitted by the Departments of the Interior and Commerce, and supports their inclusion in the license. Without the adoption of the terms, conditions, prescriptions and recommendations submitted by the Departments of the Interior and Commerce, EPA believes the license would result in unsatisfactory environmental and public welfare impacts in the Skokomish River basin, including impacts on the treaty-protected rights of the Skokomish Indian Tribe.

The FERC's Proposed License and Its Impacts

The FERC proposes to issue a license for the Project (with a 30- to 50-year time frame) requiring a minimum instream flow of 240 cfs, with "flushing flows" of 400 cfs each November. This proposed license would allow the continued diversion of over two-thirds of the unimpeded mean annual flow (784 cfs) out of the natural watercourse and would not be sufficient to ensure the recovery of the North Fork's once abundant fishery and other aquatic resources. In addition, this proposal's continued out-of-basin diversion of more than two-thirds of the North Fork's waters will result in continued aggradation of the mainstem channel, exacerbating current flooding and degradation of the Skokomish River estuary.

In general, the FERC's proposed license, as described in the EIS, would have the following unsatisfactory effects:

- continued severe adverse impacts on eight anadromous salmonid species in the Skokomish watershed;

- progressively more frequent and severe flooding in the mainstem due to continued sediment aggradation, resulting in septic drain field failures and contaminated shallow drinking water wells as groundwater levels rise;

- continued adverse impacts on the Skokomish River estuary (e.g., loss of eelgrass habitat) due to reduced freshwater flows from the Skokomish River; and

- continued significant adverse impacts on the Skokomish Indian Tribe and its associated trust/treaty resources.

Additional detailed information regarding adverse environmental impacts of the proposed license is provided in comment letters on the draft EIS from the National Marine Fisheries Service and the Department of the Interior (both letters dated March 29, 1996), and in the Department of the Interior's filings regarding section 4(e) conditions for the adequate protection and utilization of the Skokomish Indian Reservation (letters dated November 1, 1996; December 2, 1996; and, August 4, 1997).

Tribal Issues

We are particularly concerned about the continued adverse impacts of the proposed licensing, as described in the EIS, on the Skokomish Indian Tribe. The Skokomish Indian Tribe, pursuant to the Treaty of Point No Point, retained rights to reservation lands and waters, as well as the off-reservation usual and accustomed fishing, hunting, and gathering sites, including the right to take fish "in common with all [non-Indian] citizens." Court decisions have established that these treaty rights include the right to actually catch fish, and support the view that the treaty fishing right includes the right to the protection of the habitat necessary to sustain fish populations. As an agency of the federal government, the FERC is subject to the United States' trust responsibility towards federally-recognized Indian tribes. See *Covelo Indian Community v. FERC*, 895 F.2d 581 (9th Cir. 1990). In addition, consistent with President Clinton's memorandum of April 29, 1994, on the subject of government-to-government relations with Native American Tribal governments, Federal government plans, projects, programs and activities are to assess impacts on tribal trust resources. However, the final EIS does not acknowledge the FERC's trust responsibility nor does it describe the specific rights, including the fishery and shellfish rights, of the Skokomish Tribe under the Treaty of Point No Point. In addition, the final EIS does not describe whether and how the proposed licensing comports with the Tribe's treaty rights.

Moreover, when President Clinton issued Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," independent agencies such as the FERC were requested, to the extent permitted by law, to identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies and activities on low-income populations and minority populations, including Native American populations. Again, the FERC has made little effort to explicitly address impacts to the Skokomish Indian Tribe from the proposed license. For over seventy years, the Project has been a major contributor to the catastrophic decline of Skokomish River salmon, and the serious decline of other natural resources, upon which the Skokomish people have relied. The FERC's proposed license would continue to result in serious adverse and unsatisfactory impacts to tribal trust resources and thus to the Skokomish people.

The FERC's Alternatives Analysis

Given the degraded condition of the environment and the burden of that degradation on the Skokomish Indian Tribe, we believe it is essential that the FERC make every effort to carefully develop an appropriate range of reasonable alternative license proposals. Instead, the

FERC's final EIS presents an alternatives analysis that is severely lacking and, at times, misleading. Most troubling is the presentation in the final EIS of a single "resource" alternative (Alternative 2) which does not represent the proposal of any of the parties involved in this licensing and is burdened with the enormously expensive costs of constructing a new powerhouse, and purchasing Lilliwaup Swamp, which is already owned by the State of Washington, for wildlife mitigation. The FERC's alternatives analysis consequently does not present a meaningful discussion of reasonable alternatives that would provide more protection to the Tribe and the environment than the FERC's preferred alternative.

In commenting on the draft EIS, EPA recommended that the FERC identify the effects of the mitigation measures in a net-revenue analysis, where the cost of each mitigation measure could have been balanced against a quantified measure of its benefits. An alternative could then have been developed that incorporated the most cost-effective mitigation measures. The FERC did not accept that suggestion, and concluded that the only approach to balancing the competing interests in this case was to propose a license that will result in continued adverse environmental impacts.

In response to concerns raised by the applicant that many of the mitigation measures were "unaffordable," EPA has independently contracted for an analysis of a "strawman" alternative that attempts to resolve many of the environmental issues associated with the Cushman Hydroelectric Project in a manner that is economically feasible. A description of EPA's "strawman" alternative, which incorporates the section 4(e) conditions and section 18 prescriptions, as well as an analysis of the costs and potential means for financing this alternative, is enclosed.

Since issuance of the final EIS, EPA has also participated in settlement discussions with the applicant and other parties involved in this licensing. In light of the FERC's refusal to consider more reasonable alternatives in the final EIS, these discussions have necessarily focused on alternatives that were not addressed by the FERC's EIS. In addition to EPA's "strawman" proposal, other parties have developed comprehensive proposals that deserve close examination. In EPA's view, these settlement discussions have only reinforced our concern that the FERC has not fully examined an appropriate range of alternative licensing proposals.[2] Without a rigorous examination of alternatives like those developed by EPA and other parties, the FERC will not be able to develop a license that provides for an appropriate balance between power and environmental values.

We are also concerned over the FERC's method of environmental analysis with regard to the EIS's "no-action" alternative. The FERC has defined the "no-action" alternative as the continuation of present operating conditions, rather than an alternative which more accurately represents what would occur if the proposed activity did not take place, i.e., no license were issued. As a result of this approach, the final EIS concludes that the limited mitigation measures proposed by the FERC staff serve to "enhance" environment quality. While the proposed mitigation would provide a limited reduction of the level and rate of environmental degradation

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[2]It is important to note that given the FERC's strict interpretation of its prohibition on *ex parte* communications, the FERC's involvement in these settlement discussions has been limited to only infrequent participation by "non-decisional" FERC staff members.

that has persisted since 1926, the severe impacts of the past seventy years would continue to accrue, albeit at a slower pace, for an additional thirty to fifty years. Consequently, we continue to be concerned over the FERC's use in this case, as well as other relicensing proceedings, of existing degraded environmental conditions as a starting point for its balancing of competing values. The FERC's approach to this matter appears to conflict with the Ninth Circuit's instruction that "[r]elicensing . . . is more akin to an irreversible and irretrievable commitment of a public resource than a mere continuation of the status quo [and] involves a new commitment of the resource". See *Confederated Tribes and Bands of the Yakima Indian Nation v. FERC*, 746 F.2d 466, 476 (9th Cir. 1984), cert. denied, 471 U.S. 1116 (1985). Without this new look at whether the river should continue to be diverted, it is unclear how the FERC can, as required by the Federal Power Act, give equal consideration to "the protection, mitigation of damage to, and enhancement of, fish and wildlife (including spawning grounds and habitat)". See 16 U.S.C. 797(e).

Finally, we recognize that the FERC has the authority to grant Tacoma Public Utilities a license to use federal water resources for the benefit of its ratepayers, as provided for in the Federal Power Act. In exercising its authority, however, the FERC must determine whether this use will be in the public interest. To make that determination, the FERC must first explore all issues relevant to the public interest, including the benefits of *non-power* uses of the resource. See *Udall v. FPC*, 387 U.S. 428, 439 (1967). However, the FERC's economic analysis in this case treats environmental mitigation measures as imposing operational *costs* on Tacoma Public Utilities without considering the public *benefit* attributable to them. EPA believes that had the FERC compared the broad public benefits of the mitigation measures on fisheries, wildlife, sediment transport, and estuary quality to the Project's energy benefits, the FERC's view of a balanced result likely would have been different.

Conclusion

EPA believes that the FERC's proposed license would not be consistent with the National Environmental Policy Act's (NEPA) goal that federal agencies use all practicable means to attain the widest range of beneficial uses of the environment without degradation or risk to health and safety. We also believe that the FERC has not adequately considered the effect of the federal government's trust responsibilities and Treaty obligations in this license proceeding. We recommend that the FERC work with all stakeholders in this process to define reasonable alternatives that better reflect the multiple objectives associated with the proposed license, and to provide an accurate assessment of those alternatives in a supplemental EIS. EPA believes an alternatives analysis that explores a reasonable range of alternatives that includes appropriate means to mitigate the dam's ongoing adverse impacts is necessary to satisfy the FERC's NEPA and Federal Power Act obligations. Given the continued degradation of the existing environment, it is essential that the FERC take all efforts to prepare this supplement in an expedited manner, using the already extensive record developed for this proceeding to the greatest extent practicable. Moreover, we believe that the FERC should give serious consideration to requiring interim mitigation that would be in effect pending a decision on the long-term license and that provides, at a minimum, the increased flows already agreed to by Tacoma Public Utilities and described as Alternative 1 in the EIS.

We are fully committed to working with the FERC in resolving these issues, and stand ready to commit staff and resources as necessary to work with the FERC and the Project's stakeholders to reach closure on this important issue. While we will continue to actively participate in the ongoing settlement discussions between the applicant and other affected parties in this proceeding, we believe it is important that the FERC expedite a resolution of this matter.

Sincerely,

for Chuck Clarke
Regional Administrator
EPA Region 10

Enclosure

cc: Service List

Certificate of Service

I hereby certify that on January 30, 1998, I served the above Motion (Letter from Chuck Clarke, Regional Administrator, EPA Region 10 to Lois Cashell, Secretary, FERC, dated January 30, 1998 for the Cushman Project (FERC Project No. 460) in the following manner:

Lois Cashell, Secretary, FERC: hand-delivered

Project Service List: first class mail

Clifford Rader
EPA Office of Federal Activities

Economic Analysis for EPA of the Cushman Hydroelectric Project

by David Marcus, Energy Consultant

November 13, 1997

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Economic Analysis for EPA of the Cushman Hydroelectric Project

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I. Introduction

The Cushman Hydroelectric Project ("Cushman") is on the North Fork of the Skokomish River ("North Fork") in the state of Washington. The electricity produced by the project forms part of the resource mix of the Tacoma City Light ("TCL") division of the Tacoma Public Utilities ("TPU") of the City of Tacoma, Washington. TPU is currently seeking a new Cushman license before the Federal Energy Regulatory Commission ("FERC"). In that licensing proceeding the Environmental Protection Agency ("EPA") and other intervenors collectively known as the Joint Resource Parties ("JRP") have proposed that various mitigation measures be made part of any new Cushman license.

FERC has prepared Draft and Final Environmental Impact Statements (the "DEIS" and "FEIS") which describe and analyze various Cushman alternatives, including alternatives proposed by Tacoma, by FERC staff, and by the JRP.[1] In comments on both the DEIS and FEIS, Tacoma has criticized the JRP alternative created by FERC, claiming it cannot afford such a costly mitigation package in a deregulated electricity market.

This report has been prepared at the request of EPA to provide an economic analysis of: (1) the costs to Tacoma of the mitigation measures I have been asked by EPA to analyze (the "EPA straw man" mitigation measures)[2], (2) how those costs would affect the total cost of Cushman Project generation and any required replacement generation, and (3) the consequences for TCL and its ratepayers of those costs. This report does not address the either the environmental or economic benefits of the proposed mitigation measures, such as fishery and recreation benefits,

[1] Alternative 2 in the FEIS and DEIS is characterized as "the JRP Alternative" and contains many mitigation measures sought by one or more JRP members. Alternative 2, however, includes several expensive measures that are not being sought by members of the JRP (as discussed later in this report), and differs significantly from the mitigation package I have been asked to analyze.

[2] The specific mitigation measures analyzed in this report are described below in Section III. These measures and their costs were provided to me by EPA, but are intended to reflect mitigation measures sought by other members of the JRP and not just the EPA.

which FERC will be obligated to consider in any Cushman licensing decision.[3]

II. Summary of results and conclusions

The proposed mitigation package would increase the cost of electricity produced at Cushman and reduce the amount of electricity generated at Cushman, resulting in replacement generation costs. These costs could be borne by Tacoma without substantial rate increases and without jeopardizing Tacoma's competitive position in a deregulated market.

The study methodology and input assumptions are described below in the text of the report. The results are shown in the accompanying Tables 1-8 and the Summary Table. The Summary Table presents key results in terms of 1998 dollars.

A. The mitigation package would reduce average Cushman generation from 354 gwh per year to 166 gwh per year.

Tables 1 and 2 show the quantity and market value of the Cushman project's electricity with and without EPA's straw man mitigation case, for each year of an assumed 30-year license term starting in 1998. EPA's straw man conditions substantially reduce the quantity of Cushman generation, from an average of 354 gwh per year to an average of 166 gwh per year.[4] The wholesale value of each kwh of generation increases each year in nominal terms. Excluding the effects of inflation, the wholesale unit value of generation averages $18.82 per Mwh (18.82 mills/kwh, or 1.882 cents per kwh) over the license term, when expressed in 1998 dollars.[5]

B. The cost to Tacoma of Cushman generation plus replacement generation costs, averaged over a 30-year license, would increase from the current level of under $10/Mwh to over $32 per Mwh with the mitigation package

[3] For example, FERC has estimated that the annual economic value of sportfishing benefits associated with fish passage at Cushman would be $3 million per year in 1996 dollars (FEIS, p. C21; note that Table C-7 shows an annual economic value of fish passage of over $12 million).

[4] Summary Table, columns 2-4. Annual generation would vary because of both hydro variability and the phase-in of various mitigation measures affecting Cushman generation. Phase-n effects are shown in Table 1, column 7.

[5] Summary table, column 5 and Table 6, column 7.

Tables 3 and 4 show the capital-related and total annual costs of operating Cushman with and without the EPA straw man proposals. The EPA straw man proposals increase both capital costs and operating and maintenance ("O&M") costs. They also result in costs for replacement energy because of the lower generation which occurs with the EPA straw man proposals. The phase-in of mitigation measures over the first six years of the license period makes mitigation less costly than if it were all done at once. Averaged over the license term, however, the cost of producing electricity from Cushman rises from the current cost of just under $10 per Mwh (under 1 cent per kwh) to just over $32 per Mwh (over 3 cents per kwh) with EPA's straw man mitigation measures.[6] By comparison, TCL has proposed mitigation measures which would result in Cushman costs roughly equal to the market value of electricity, or about $19 per Mwh.

Tables 5 and 6 combine the value and cost analyses to compute the net cost of Cushman generation in excess of its wholesale value if the proposals are adopted. They show that the average annual cost of Cushman generation with the EPA straw man mitigation would exceed its wholesale market value in all years. Above-market costs range from $1.3 million in 1998 to $8.6 million in 2027.[7] Expressed in 1998 dollars, Cushman costs with the EPA straw man mitigation package average some $4.8 million per year above market value.[8]

C. TCL retail rates would need to increase by an average of approximately 3.8 percent (less than 1/8 cent per kwh) to cover the costs of the EPA straw man mitigation package.

Table 7 shows the consequences for TCL and its ratepayers if the EPA straw man proposals are adopted. Rather than costing between $2.3 million (in 1998) and $10 million (in 2027) per year less than its market value (as it would if the present situation were continued into the future), Cushman generation would cost from $1.3 million (in 1998) to $8.6 million (in 2027) per year more than its market value.[9] Since Tacoma itself has proposed Cushman mitigation that would raise Cushman

[6] Summary Table, column 6.

[7] Table 5, column 8 and Table 6, column 8.

[8] Summary table, column 8, "EPA straw man proposal" row.

[9] Table 7, columns 6 and 7 ("Below market costs at existing Cushman" and "Above-market costs at Cushman w/ EPA straw man proposal"), showing annual values for 1998-2027.

costs to market value,[10] the cost of the EPA straw man proposal compared to the Tacoma proposal would be the $1.3-8.6 million per year that the EPA straw man proposal would cost in excess of market value.[11]

TCL's current annual electric revenue is about $200 million per year.[12] Covering the total Cushman-related cost increase of $3.6 million (in 1998) to $18.6 million (in 2027) per year would require TCL to raise its average rates by 1.9 percent initially, 4.7 percent in the worst single year (2005), and an average of 3.8 percent over the assumed 30-year license term.[13] Of that 3.8 percent rate increase, at least 2/5 would be necessary if Tacoma's mitigation proposals were adopted instead of the straw man mitigation package put forth by the EPA.[14]

D. TCL's retail electric rates would remain low and competitive even with a 3.8 percent rate increase.

Table 8 shows how TCL's rates compare to those of other Pacific Northwest ("PNW") electric utilities, before and after a 3.8 percent rate increase.[15] TCL

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[10] Summary Table, "FEIS, TCL alternative" line.

[11] Tacoma characterizes its own Cushman proposal as an above-market proposal, with a cost "slightly above" the cost of long-term firm energy supplies (TPU, "The Cushman License: An Issues Discussion Paper," ("White Paper"), 1/10/97, p. 3, fn. 6.). Using Tacoma's methodology (White Paper, p. 7, fn. 17), Tacoma's own proposal would have above-market costs of $1.9 million per year in 1998 dollars. To the extent Tacoma's proposal is indeed an above-market proposal, the difference between Tacoma's proposal's costs and the costs of the EPA straw man proposal is less than the $1.3-8.6 million per year figure given here.

[12] Table 7, column 4.

[13] Table 7, column 13.

[14] Summary Table, column 13. Increasing Cushman's cost to market price, which is roughly Tacoma's proposal, would itself require a 1.5 percent increase in average TCL retail electricity rates over the otherwise applicable level, or 2/5 of the 3.8 percent increase required to pay for the EPA straw man proposal. Tacoma itself characterizes its proposal as resulting in Cushman costs somewhat above market value, implying a required average rate increase of more than 1.5 percent.

[15] Table 8 assumes a rate increase above current rates equal to the 30-year average rate increase under the EPA straw man proposal. Table 7, column 13 shows the corresponding year-by-year percentage rate increases, which are less than or equal to 3.8 percent in 16 of the 30 years analyzed, and higher in the other 14 years. Even using

currently has some of the lowest rates in the region, and its average rates are about half the national average. An increase to cover Cushman mitigation costs would leave Tacoma's position basically unaffected - it would still have some of the lowest rates in the region, it would still have substantially lower rates than its non-municipal competitors, and it would still have rates far below the national averages. In quantitative terms, the EPA straw man proposal would result in an average TCL rate only $0.70 per Mwh (or 0.07 cents per kwh) higher than if Cushman generation's cost was equal to its market value.[16]

E. Tacoma can recover above-market costs ("stranded costs") of Cushman generation through rates.

1. Recovery of stranded costs is legal.

EPA's straw man mitigation costs would result in Cushman costs above the market value of Cushman generation. Such costs are known as "stranded" costs in industry jargon. In a purely competitive generation market such costs could not be successfully charged to customers, since customers would simply shift to a different generation supplier who did not have above-market costs. However, FERC has made clear that utilities are to be generally allowed to recover stranded wholesale costs.[17] More important, since Cushman generation is sold at retail and not at wholesale, and hence is not subject to FERC jurisdiction, there is no legal bar to Tacoma recovering stranded Cushman costs in its retail rates. Indeed, Tacoma retail rates today already include costs associated with above-market generator costs.[18]

2. Recovery of stranded costs is practical

Tacoma has objected that even if it can legally recover stranded costs, it cannot do so in the face of competition, because customers will switch to alternative suppliers in the competitive retail electricity market which is now

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the worst single year's required increase, 4.7 percent in 2005 (Table 7, column 13), would have no effect on TCL's relative position versus the other utilities shown in Table 8.

[16] Summary Table, column 9.

[17] FERC, Orders 888 and 888A.

[18] See discussion below. Above market costs which are currently embedded in TCL's retail rates include WPPSS 1 and 3 costs, mid-Columbia hydro costs, steam plant #2 costs, and Centralia coal plant costs.

evolving. This fear is unfounded.

Most TCL customers will remain physically connected to the TCL system, but will be offered the opportunity to choose alternative generation suppliers. This is known in industry jargon as "direct access." For these customers, TCL can recover above market generation costs through a nonbypassable stranded cost charge separate from its competitive generation charge. Such a charge, which is being implemented in California, assures that customers cannot evade certain above-market costs by switching suppliers. The mechanics of implementing a nonbypassable stranded cost charge are described in Appendix 2.

Tacoma has raised the specter of a "death spiral," in which rate increases lead to increased conservation and customer departures, which results in costs being spread over a smaller volume of kwh sales, which leads to further rate increases, and so on. A death spiral will not result from Cushman license conditions, since the rate increases associated with implementing the EPA conditions would be small. In any case, rate design which places above-market costs into fixed portions of rates rather than into variable portions would obviate the incentive to reduce consumption which is needed to create a death spiral.

F. Whether Tacoma will want to accept EPA's straw man levels of mitigation if FERC includes them as license conditions is outside the scope of this study.

My analysis shows that Tacoma will have to forego existing below-market cost savings of millions of dollars per year at Cushman with its own mitigation plan that results in near-market-value Cushman costs, and will also have to incur above market costs of millions of dollars under the EPA straw man proposal.[19] As described below, above market costs of mitigation, by themselves, are neither a reason for FERC to reject a proposed mitigation plan, nor a reason for Tacoma to reject a license including such a plan.

From the FERC point of view, the **Mead** decision makes clear that FERC's legal obligations to balance economic and environmental concerns can and will result in license conditions that make projects seemingly uneconomic. In the first year and a half after **Mead**, FERC has issued numerous licenses which had (according to FERC's economic analysis) negative net economic values associated with them. From Tacoma's point of view, as FERC has made clear, there are two main reasons why a license with apparently negative economic consequences could still be accepted and its conditions implemented.

1. <u>The consequences of the EPA straw man case may not be as adverse as portrayed here</u>

[19] Table 7, columns 6 and 7. Summary Table, column 8.

First, the negative economic consequences of the EPA straw man proposal may not be realized. The analysis in this report assumes a near-worst-case, not a most-likely case, as described below. A license is good for 30 to 50 years, and over that time economic conditions can change sharply. Within the last decade, Tacoma has itself made investments at Cushman which were predicated on a long-term market value of electricity of more than triple today's forecasts, and more than double the cost of Cushman with EPA's straw man mitigation case.[20] Cushman, even with EPA straw man mitigation, may be a very cost-effective insurance policy against future increases in market prices due to natural gas price increases or any other cause.[21] I have not performed any analysis of the option value to Tacoma of retaining Cushman as an insurance policy against market price increases.

2. Even an above-market-cost project can be cheaper than rejecting a project license

Second, the negative economic consequences associated with a new license may be smaller than the negative economic consequences associated with rejecting the new license.[22] Tacoma must compare the cost of a new license not to the simple cost of replacement energy if it rejects the license, but also to the costs other than replacement energy which it will incur if it rejects the license. These include sunk cost recovery for past Cushman costs,[23] litigation costs regarding

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[20] See section IV.C.1.e., below.

[21] Plausible "other causes" for market prices to increase above currently anticipated levels include long-term inflation above 3 percent per year.

Price increases in PNW electricity markets could also occur due to arbitrage between PNW and California market prices once retail competition begins in California in 1998. Such increases would occur as PNW utilities make sales to California retail customers (as numerous PNW utilities, public and private, have already contracted to do). Out of region sales by PNW generators decrease the supply of PNW energy resources to meet PNW loads. As in any competitive market, decreasing supply will, ceterus paribus, cause prices to rise. The potential rise in PNW prices is capped only by California prices, since as long as California prices (net of transmission costs) are higher than PNW prices, PNW generators will have an incentive to sell to California rather than to PNW customers.

[22] See FERC, Mead, p. 8, explicitly noting that the expense of decommissioning may cause licensees to accept a license with conditions that would be economically untenable in the case of a new license.

[23] My analysis of future costs to Tacoma ratepayers assumes they will be charged rates to recover the approximately $30 million of net undepreciated Cushman capital

Tacoma's post-license obligations at Cushman, and any resulting costs at the now-shut Cushman for ongoing maintenance or facility decommissioning.[24] The FEIS shows that even the simplest form of decommissioning, abandonment of all facilities in place, would have average annual costs almost as high as the cost of a new license with EPA's straw man mitigation.[25] Any other form of decommissioning (e.g., a requirement that Tacoma either remove the existing dams or modify them to allow post-decommissioning fish passage, or a requirement that Tacoma modify the Cushman 2 power plant to allow it to continue to be used for flood control purposes after it ceases to produce electricity) would cost substantially more.[26] I have not performed any analysis of the economic consequences for Tacoma if it rejects a FERC license for Cushman.

G. The estimated costs of the EPA straw man proposal are near-worst-case results, and will likely be less severe than estimated.

The study results summarized above are in many ways worst-case results, in the sense that they are based on numerous assumptions[27] that tend to overstate the

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costs which are currently on TCL's books. Those costs will continue to be on Tacoma's books whether or not Tacoma accepts a Cushman license from FERC.

[24] See FERC, Docket RM93-23-000, Policy Statement, 12/14/94, p. 3, stating that "in those instances where it has been established that a project will no longer be licensed ... the project **must** be decommissioned." (emphasis added)

[25] Summary Table, column 8. Compare the "EPA straw man proposal" row to the "FEIS, decommissioning" row. The average cost difference between the two alternatives is only $2 million per year, in 1998 dollars.

[26] The existing Cushman 2 powerhouse allows the diversion of up to 2700 cfs out of the North Fork of the Skokomish River directly to Hood Canal (memo from James E. Borg of Harza to Steven H. Fischer of TPU, 1/19/96, p. 1). If the Cushman 2 powerplant were shut down, such diversions "could result in a catastrophic failure of the powerhouse (memo from Richard J. Titemore of Voith Hydro to David Beech of TPU, 11/22/96). Closure of the Cushman 2 powerhouse after a license surrender would therefore, absent post-closure modifications, increase peak releases to the lower North Fork Skokomish by 2700 cfs over the level under either current operations or the EPA straw man proposal. The cost of modifying the Cushman 2 powerhouse to allow flood control releases without power generation "could be in the millions of dollars" (memo from James E. Borg of Harza to Steven H. Fischer of TPU, 1/19/96, p. 2).

[27] These include assumptions regarding flood control costs, in-stream flow requirements, license term, BPA billing credits, and others. Individual assumptions are

economic costs of the EPA straw man mitigation measures. For example, in-stream flows are assumed at the maximum level required under the proposed mitigation package in order to increase North Fork bankfull capacity, without regard to lower flows that might actually be allowed under adaptive management. High in-stream flow requirements reduce potential electricity generation and thus increase the cost of Cushman generation. Yet at the same time, the high in-stream flows are assumed to be ultimately unsuccessful in increasing channel capacity, requiring the expenditure of $5 million for channel deepening.

H. The study results are similar to FERC's FEIS results for the existing project and market-priced project cases, but not for the EPA straw man case.

1. <u>The study results are consistent with the FEIS results for the no-action case.</u>

The study shows an average cost for 354 gwh of Cushman generation in 1998 dollars for the no-action (existing project) case of $9.3/Mwh, or $3.2/Mwh less than the $12.5/Mwh shown in the FEIS.[28] This difference is small in absolute terms, and a substantial portion of it is due to FERC's omission of any credit for the BPA billing credit which Tacoma receives from BPA in recompense for past Cushman capital expenditures. The FEIS also used a cost of capital to compute Tacoma's sunk cost recovery expense which was not reflective of Tacoma's actual cost of debt. Finally, FERC's post-**Mead** economic analysis methodology ignores the fact that not all future costs will trend with inflation.[29]

2. <u>The study results are consistent with the FEIS results for a market-priced case.</u>

Tacoma has proposed, **de facto**, that it will spend on future mitigation the dollars that it would otherwise save from the below-market cost of the existing Cushman project. The FEIS thus shows a Tacoma-proposed alternative in which the

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discussed in the text below.

[28] Summary Table, column 6.

[29] Table 6, column 13 shows annual estimated costs for the existing Cushman project. Those costs increase annually, but not as fast as general inflation, so that the average cost in 1998 dollars is lower than the nominal cost in the year 1998. The 1998 cost, $10.41/Mwh, is considerably closer to the FERC value of $12.5/Mwh than the 1998-2027 average cost of $9.26/Mwh.

market value and operating costs of Cushman are basically identical.[30] The market price of electricity in the FEIS is $22.3 per Mwh in 1998 dollars,[31] 18 percent higher than the average value of 18.8 mills per kwh computed in this report.[32] The difference is small compared to the range of differences which can be found in various forecasts of the future market price of electricity over a 30-year term. It is due to the use of Tacoma's consultant Henwood's market values for energy in this report, but the exclusion of any capacity value. As discussed below in the section on model inputs, Henwood assigns a value to both energy and capacity while FERC expresses all value in energy terms. This analysis, conservatively, uses Henwood's energy prices, adjusts them downwards for a lower general inflation assumption, and assumes that they already incorporate the value of capacity.

3. <u>The large discrepancy between the EPA straw man case results in this report and the JRP case results in the FEIS exists largely because the EPA straw man proposal omits major components of FERC's "JRP" case</u>.

This report shows an EPA straw man case average cost of $8.2 million per year (in 1998 dollars) more than the existing Cushman project cost,[33] barely a third of the $22.1 million per year extra cost attributed to the JRP case in the FEIS.[34] The bulk of the $13.9 million per year difference occurs because the FEIS has attributed to the JRP case costs which are not in the EPA straw man case. Thus, the costs of the EPA straw man case are far lower than the JRP case costs presented in the FEIS.

The FEIS includes as part of the JRP case two high capital cost items which are not part of the current EPA straw man proposal. These consist of a new powerhouse number 3 at the foot of the lower dam, at a cost of $32 million, and $119 million for wildlife habitat acquisition rather than the $32.4 million figure used

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[30] FEIS, Table 5-6. Summary table, "FEIS, TCL alternative" line, comparing columns 5 ("average value/Mwh") and 6 ("cost/Mwh").

[31] Summary Table, column 5.

[32] Summary table, column 5.

[33] Summary Table, column 8, difference between "Existing project" and "EPA straw man proposal" lines.

[34] Summary table, column 8, difference between "FEIS, existing project" and ("FEIS, JRP alternative") lines.

in this report.[35] These two changes alone to the so-called JRP case in the FEIS reduce the capital cost of the EPA straw man case by some $127.7 million in 1998 dollars, which corresponds to about $10 million per year in 1998 dollars, using the FEIS's cost of capital methodology. Another $1.2 million per year of the difference is due to the FEIS's assignment of shellfish enhancement O&M costs to Tacoma,[36] which is not part of the current EPA straw man proposal. The balance of the difference is due to a variety of factors, including the fact that Tacoma's incremental cost of capital (what Tacoma currently pays to borrow money) of 5.6 percent per year is well below the 7 percent assumed by FERC.

I. Other issues - TCL's large industrial customers and its "Non-Portfolio Power Service" tariff

EPA has asked for an explanation of the recent shift by Tacoma's largest industrial customers ("CP" customers) to obtain energy priced at market rates below those charged to Tacoma's other customers. As discussed in Appendix 3, this turns out to be a special situation not directly linked to the Cushman issue. Only five customers are involved, the tariff expires in 2001, and the tariff is linked to a BPA contract amendment which results in a net reduction in both Tacoma's costs and CP customer's rates. These special circumstances will not apply for any other customers. Tacoma will face the same issues with regard to passing through above-market Cushman costs to CP customers as with any other customers.

III. Description of the EPA straw man mitigation package

The EPA straw man proposal for Cushman has several components, which affect capital costs, O&M costs, as well as in-stream flows and hence generation. Each of these components is described below, along with an estimate of the costs for each component. Table 11 summarizes the EPA straw man mitigation measures other than flow modifications. The total capital cost for mitigation measures is forecasted to be $56.5 million in 1996 dollars, with annual ongoing costs of $1.8 million per year in 1996 dollars.[37]

[35] FEIS, Table 5-3, p. 5-5. The FEIS figures are in 1996 dollars.

[36] FEIS, Table 5-3, p. 5-5.

[37] Table 11, line 20.

A. Flows

I assumed an average annual release from Lake Kokanee of 813 cfs to the lower North Fork plus Cushman powerhouse number 2, based on the 70-year mean.[38] Most of this release was assumed to go to the North Fork, with the balance available for power generation at Cushman powerhouse number 2.

Releases to the North Fork were based on revised 4(e) conditions 1-3 and 11, as quantified in the 8/15/97 Stetson Engineers Technical Memorandum to Bernie Burnham of the BIA. Average annual releases to the North Fork rise immediately from the current 30 cfs to 507 cfs in 1998-2000, and then to a maximum level of 708 cfs in years 8-30. Most of the release requirement is driven by revised 4(e) condition 11, since conditions 1-3 collectively require average annual releases of under 300 cfs. 708 cfs is some 87 percent of the total average flow of 813 cfs.

The North Fork release assumptions are probably worst case assumptions. They leave only 13 percent of native flow for power generation, close to the physical minimum of zero. They are based on a higher percentage of water staying in the North Fork than Stetson calculated, since I used Stetson's release numbers but not Stetson's natural flow number of 842 cfs. They ignore the adaptive management language of revised 4(e) condition 10, under which reduced average flows are possible.

B. Fish

1. Fish passage facilities

Fish passage past Cushman dams 1 and 2 is a key part of the EPA straw man proposal.[39] The expected capital cost will be $10.526 million (1996 dollars), to be spent in 2000-2001, plus a subsequent O&M cost of $300,000 per year (1996 dollars).

2. Fish habitat development projects

The EPA straw man proposal includes $56,000 per year (1996 dollars) for Lower North Fork habitat restoration.[40]

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[38] Clint Kalich, TCL, personal communication, 9/97.

[39] Table 11, line 2. Fish passage facilities are in revised 4(e) condition 6.

[40] Table 11, line 3. Fish habitat development is revised 4(e) condition 7.

3. <u>Fish stocking and supplementation</u>

Fish stocking in the lower North Fork, Lake Cushman, and its tributaries is part of the EPA straw man proposal. The expected capital cost will be $1.526 million (1996 dollars), to be spent in 2000-2001, plus a subsequent O&M cost of $150,000 per year (1996 dollars).

4. <u>Hatchery upgrades and O&M contribution</u>

The EPA straw man proposal calls for TCL to contribute $3.6 million in capital towards renovation and ongoing operation of the George Adams Hatchery, plus $500 thousand per year to offset part of the cost of operations and maintenance of the State's hatchery facilities for the Skokomish River Basin (both in 1996 dollars).[41] The capital contribution is assumed to be spent in the second year of the new license period, or 1999, with the annual contribution starting the same year.

C. Shellfish

The EPA straw man proposal includes $1.2 million for the capital costs of shellfish culture and seeding in year 2 of the new license, or 1999.[42] No costs are assigned to TCL for ongoing shellfish O&M. The FEIS, in contrast, included a smaller capital cost but over $1 million per year in annual O&M for shellfish.

D. Wildlife

The EPA straw man proposal includes $32.4 million for habitat acquisition plus $443 thousand per year for O&M (both in 1996 dollars).[43] Capital expenditures are assumed to be spread across the first four years of the new license, with O&M expenses increasing proportionately.

E. Recreation

The EPA straw man proposal includes $1.42 million in capital costs and $194,000 per year in O&M for recreational facility improvements.[44] These are the

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[41] Table 11, line 12.

[42] Table 11, line 14.

[43] Table 11, lines 15 (capital) and 19 (annual expense).

[44] Table 1, line 13.

same measures and costs which are included in the FEIS under its JRP alternative.[45] Capital costs are assumed to be incurred in years 2-4 of the new license, or 1999-2001, with O&M expenses increasing proportionately as capital outlays occur.

F. Dam modification

Increasing releases to the North Fork above the current 30 cfs may require modification of the existing spillgate at the lower dam.[46] TCL estimates this will cost some $2 million (1996 dollars).[47] TCL's 1997-98 budget already includes $0.5 million for spillgate modification, but this money has not yet been spent.[48] I have included the entire $2 million as a mitigation cost in the first year of a new license,[49] and excluded it from the capital costs associated with the existing facilities (see discussion below of capital additions at existing facilities).

G. Flood control

If increased flows are unsuccessful in increasing the main stem channel capacity sufficiently, then other means will be necessary. The revised 4(e) conditions call for a review after 5 years.[50] I have made the worst-case assumptions that the 5-year review will find that increased in-stream flows have been insufficient, and included a $5 million capital cost (in 1996 dollars) in year 6 of the new license, to pay for main stem gravel removal.[51]

H. Miscellaneous - studies, McTaggert Creek, etc.

The EPA straw man proposal includes a variety of relatively low-cost mitigation measures. These include removal of the McTaggert Creek diversion

[45] FEIS, Table 5-3, p. 5-5.

[46] See revised 4(e) condition 4.

[47] Clint Kalich, TCL, personal communication, 9/97.

[48] TPU, 1997-98 Biennial Budget; TCL, personal communication, 9/97.

[49] This assumption is conservative, since revised 4(e) condition allows up to 5 years for dam modifications, with manual manipulation of the Dam #2 spillway gates allowed in the meantime.

[50] Revised 4(e) condition 11.

[51] Table 11, line 6.

dam,[52] installation of telemetered stream gages,[53] a variety of studies and reports regarding flow regime effectiveness,[54] transmission line right-of-way wetlands and wildlife management,[55] cultural resources curation and training programs,[56] restoration of riparian habitat in the lower North Fork,[57] gravel restoration between Dam #2 and the mouth of McTaggert Creek,[58] and a fish population monitoring plan for the North Fork.[59] These measures will have a collective capital cost estimated to be $364,000, plus an annual cost of $170,000, in 1996 dollars.

I. Other - potential reduction in BPA billing credit

BPA currently makes "billing credit" payments to TCL based on an estimated 11.7 gwh per year increase in Cushman project generation associated with turbine runner upgrade projects carried out by TCL in the past. These payments currently exceed $500,000 per year, but will decline over time as the gap between TCL's sunk cost of improvements and BPA's wholesale rates narrows.[60] TCL staff have suggested that, if Cushman generation is reduced by the EPA straw man mitigation measures, BPA may argue that it is no longer getting the 11.7 gwh of efficiency

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[52] Revised 4(e) condition 9. See Table 11, line 5.

[53] Revised 4(e) condition 5. See Table 11, line 7.

[54] Revised 4(e) condition 10. See Table 11, line 8. Annual costs include a Skokomish River Flow Report and numerous supporting studies. One-time costs include an IFIM study in year 10 of the new license.

[55] Revised 4(e) condition 12. See Table 1, line 9. FERC estimates a cost of $37,000 per year for this measure (FEIS, p. 6-35). EPA shows the $37,000 as a capital cost rather than an annual cost (EPA, 11/6/97 fax). Northwest Economics estimates a cost on Tribal lands of only $6,000 per year, plus a capital cost of $11,000. I have used an intermediate value based on Northwest Economics' capital/O&M ratio and EPA's capital cost estimate.

[56] Revised 4(e) conditions 13-14. See Table 11, lines 10-11.

[57] Table 11, line 16.

[58] Table 11, line 17.

[59] Table 11, line 18.

[60] See Table 3, column 7, for a year-by-year forecast of the future BPA billing credit.

improvements that are embedded in the contract and hence should not have to pay for them.

The legal validity of this TCL argument is completely unknown. Certainly TCL is unlikely to voluntarily accept reduced payments from BPA. However, as a worst case assumption, I have assumed that annual BPA billing credit payments are reduced for Cushman 2 in proportion to the reduction in its generation associated with EPA's straw man flow conditions.[61]

IV. Net cost of Cushman with and without the EPA straw man proposal

A. General methodology

The general methodology used in this analysis is simple. I first compute the value of Cushman generation with and without the EPA straw man mitigation measures. I then compute the cost of operating the Cushman project with and without the EPA straw man mitigation measures. The difference between the value and cost of the project without the EPA straw man mitigation measures is the above-market cost of the existing project. The difference between the value and cost of the project with the EPA straw man measures is the above-market cost of the EPA straw man proposal. The difference between the two above-market costs is the economic impact of the EPA straw man proposal relative to the existing projects.

A third alternative involves Cushman mitigation which makes the cost of Cushman equal to the market value of its generation. For this alternative, the value and cost of Cushman would be the same, and the above-market cost is zero by definition.

Because the EPA straw man proposal would reduce the quantity of Cushman generation, the cost of operating Cushman in the EPA straw man case must also include the cost of replacing the Cushman generation which would occur with current operations but would not occur in the EPA straw man case. Thus both cases, with and without the EPA straw man mitigation, reflect costs and values associated with delivery of the same amount of electrical energy to Tacoma.[62] In the no action case, all of the energy comes from Cushman, while in the EPA straw man case energy comes from Cushman generation and also from the purchase of replacement energy.

Inclusion of replacement energy costs in the analysis is necessary. TCL staff have suggested that "melding" generation costs incurred at Cushman with the costs

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[61] Table 3, column 14.

[62] Summary Table, column 4.

of replacement generation will understate the cost per kwh of the EPA straw man proposal.[63] When costs are expressed in dollar terms, it is a failure to include replacement energy costs which understates the cost of the EPA straw man proposal, not their inclusion. Failure to include replacement energy costs would understate the cost of the EPA straw man case by an average of over $3.5 million per year, in 1998 dollars.[64] Even when costs are expressed in dollars per Mwh terms, failure to include replacement energy costs and quantities results in inappropriate or uninformative comparisons.[65]

B. Value of Cushman generation

1. Methodology

a. Value should be based on wholesale prices

The economic value of Cushman generation is its opportunity cost to TCL. In other words, if TCL was not getting generation from Cushman, it would have to obtain generation from somewhere else. Assuming that the "somewhere else" is the open market, and not increased generation at an existing TCL resource, then market prices for generation define the value of Cushman generation. Those prices are wholesale prices, the prices charged by one utility (or non-utility) generator to another. They are not, as some parties' analyses have implied, the retail price at which TCL ultimately sells Cushman and other energy. Retail prices include not only a wholesale generation component, but also costs for transmission, distribution, metering and billing, and other TCL overhead costs.

b. The time-weighted average annual energy price is an

[63] Clint Kalich, TCL, phone conversation, 11/7/97.

[64] Table 6, column 3.

[65] Consider, for example, two alternatives A and B, where A produces 300 gwh per year at a cost of $20/Mwh and B produces 200 gwh per year at a cost of $25/Mwh. If replacement energy is not considered, B is more expensive than A in dollars per Mwh terms, by a margin of 25 percent. On the other hand, B is cheaper than A by $1 million per year. Comparing different-sized A and B is simply not informative. Only by adding in the extra costs for project B to match project A's output can a meaningful comparison be made. In this example, if replacement energy is less than $10/Mwh, the melded cost of B plus 100 gwh of replacement energy will be less than the cost of A, for the same output level, and B will be the economically preferable option.

acceptable proxy for the value of Cushman generation.

If the value of Cushman generation is the wholesale market, the question then becomes "which wholesale market?" Energy is sold on both a firm and non-firm basis, in a spot market where prices can change every hour of the year, and in longer-term markets such as the Nymex futures market. Bilateral contracts can have terms ranging from hours to years.

The FEIS, and the DEIS before it, assume a single annual value for energy. I have done the same, but not because I believe that every kwh produced by Cushman will be of equal value, whether it is proposed during the hour of peak demand or at 3 a.m. on Easter Sunday at the peak of the Columbia River runoff. Rather, I have examined the variations in price from on-peak to off-peak periods and from one month to the next, and matched those variations against the variations in Cushman generation between on-peak and off-peak periods and between the months of the year. The results of that analysis are shown in two tables.

The first table[66] uses actual on and off-peak prices for each of the last 12 months and the corresponding Cushman generation. It shows that the time-weighted average price of 16.27 mills per kwh is only slightly less than the generation-weighted average price of 16.34 mills per kwh. In other words, actual Cushman generation per hour in the last 12 months was very slightly greater in on-peak hours than in off-peak hours, but only by enough to make the value of Cushman generation 0.4 percent greater than if Cushman generation had been equal in all hours. Thus it is reasonable to use a simple time-weighted combination of on-peak and off-peak prices to value Cushman generation.

The second table[67] uses average monthly generation at Cushman for the entire 16-year period for which monthly generation data was available. The monthly average generation was then multiplied by monthly average prices from the last year to identify whether or not there is a seasonal premium value to Cushman generation even if there is no time-of-day premium value. This table shows that over half of the value of Cushman generation occurs in the months of November - February, and less than 1/5 in the period April - August. However, over the year as a whole, the extra value that results from Cushman generation being concentrated into certain months is just 0.4 percent. As with daily on-peak/off-peak generation, the annual pattern of Cushman generation does not provide any significant enhanced value for the project.

Based on these two analyses, and the further assumption that TCL has been

[66] Table 9, "On-peak/off-peak shaping of Cushman generation and its effect on project value."

[67] Table 10, "Effect of monthly generation pattern and monthly variation in value on value of Cushman generation."

operating Cushman to maximize its economic value subject to the various constraints which apply to it, I have made the simplifying assumption that a time-weighted average annual energy price provides an accurate proxy for Cushman value, albeit one slightly on the low side.

2. Model inputs and assumptions

a. Inflation rate

The future rate of inflation is often a key driver in long-term models. Inflation rates were such an oft-litigated and never resolved issue in FERC hydro licensing proceedings that FERC decided in 1996 (in the Mead decision) to adopt a new economic methodology in which future inflation would be ignored. However, ignoring inflation doesn't make it go away, and I have included a forecasted inflation rate of 3 percent per year in my analysis. Three percent is lower than the 3.5 percent used by TCL's consult Henwood Energy Services, Inc. ("Henwood") in its forecast of generation value.[68] It is higher than the market forecast of inflation over the next ten years, 2.3 percent per year, which is implicit in the differential between the yield on 10-year Treasury notes with and without inflation adjustments.[69] It is the same value used by TPU in its most recent bond sale.[70]

I have tested the sensitivity of my analysis to the inflation rate assumption by rerunning my model using FERC's unrealistic assumption of zero future inflation. Setting the general inflation rate to zero has numerous effects in my model. For example, it affects the cost of replacement energy, the value of Cushman generation, future retail rates, the BPA billing credit, and the capital and O&M costs associated with both the existing project and the various mitigation measures. But it has only minor impacts on the results. The net difference in costs between the existing project and Cushman with the EPA straw man proposal rises from $8.2 million per year to $8.8 million per year. The average rate increase required to pay for that cost increase rises from 3.8 percent to 3.9 percent.

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[68] Henwood Energy Services, Inc., "Valuation Analysis, Cushman Hydroelectric Project," 3/27/96, included as Appendix B to TPU's comments on the DEIS.

[69] NY Times, 11/7/97, p. C22. Ten year inflation-adjusted Treasury notes yield 3.53 percent per year. Ten-year Treasury notes without any adjustment for inflation yield 2.30 percent more, or 5.83 percent. The differential in yield is the market's expectation of inflation over the next ten years.

[70] TPU, Bond Prospectus ("Prospectus"), 1/15/97.

b. Energy value

I have used the annual marginal energy forecasts from TCL's consultant Henwood, adjusted downward for my use of a lower inflation rate than Henwood, as the measure of energy value.[71] The Henwood analysis is based on a grid-wide marginal cost analysis which takes into effect transmission constraints and actual powerplant operating characteristics. This is a considerably more rigorous approach to forecasting future market values than that taken in any of the other Cushman documents I have reviewed. It has the further advantage of producing annual price forecasts that take account of changing resource and load conditions in the future.

The Henwood approach has one major drawback. Because it is dependent on a myriad of data inputs (e.g., future loads and resource additions, and the operating characteristics of all operating generating units), it is only as good as its data. The absence of accurate data (e.g., burner-tip coal costs) tends to introduce error, albeit without any particular bias upwards or downwards. The Henwood approach will also tend to underestimate marginal costs because it assumes no market power and market inefficiency: all generators operate whenever they are capable of operating and producing an operating profit, and operation of the entire grid is cost-minimized.

I have compared the Henwood results (published in March 1996 and largely based on 1995 data) to actual market prices for the period 9/96 - 9/97. For that period, on-peak and off-peak nonfirm energy prices at the California-Oregon border ("COB") are available on an almost daily basis from the website of the energy consulting firm LCG.[72] TCL has identified those COB prices as "reasonable proxies for the price of available replacement power or as a point of economic comparison for the Cushman Hydroelectric Project."[73] The time-weighted average nonfirm COB price for 9/96 - 8/97 was $16.40/Mwh, and for 10/96 - 9/97 it was $16.87/Mwh.[74] The corresponding Henwood forecasts are $16.27/Mwh and $16.31,[75] or about 1-3

[71] Henwood's annual energy price forecasts extend through 2025 (Henwood, 3/27/96, p. 21). I have extrapolated Henwood's 2024-2025 rate of increase to the years 2026 and 2027.

[72] LCG, <www.energyonline.com>.

[73] TCL, Joe Taffe to Garth Jackson memo, 2/21/97, p. 1 (footnote 1 specifically cites LCG and www.energyonline.com as a source for COB prices).

[74] For the year ending 9/97, only data through 9/24/97 was available.

[75] Henwood, 3/27/96, p. 21. I have adjusted the Henwood figures downward for the 0.5 percent per year difference in our inflation rate assumptions for 1996 and 1997, and

percent below the actual nonfirm price. Given the substantial variability in actual prices, I have ignored this 1-3 percent difference rather than recalibrating the Henwood figures to be slightly higher.

The Henwood price forecasts assume an underlying general inflation rate of 3.5 percent per year, slightly above my assumed rate of 3 percent per year, and link all fuel cost inflation rates to the general inflation rate.[76] I have therefore reduced the Henwood forecasts by the ratio of 1.03/1.035, or about one half percent per year, for each year after the Henwood base year of 1995. The resulting set of annual energy values is shown at several places in the attached Tables.[77] Because the Henwood model takes account of changing resource mixes over time, its energy prices do not escalate at a constant rate. The summary table shows the 1998 energy value which, if held constant in 1998 dollars, equates to the time-varying sequence of energy values computed by Henwood. That energy value is $18.82/Mwh in 1998 dollars.[78]

c. Capacity value or firm energy value

Electrical energy values have traditionally included two separate components, energy and capacity. The energy value is the value of the actual delivered kwh. The capacity value is the value associated with the capability of delivering energy. At Cushman, for example, the average capacity of the project (the average output level) is about 40 Mw, well below the installed capacity of 131 Mw.[79] On the other hand, the existence of storage at Cushman Reservoir allows Tacoma to release flows (and hence produce kwh) well above average in any particular hour it wants to, subject only to the various constraints on reservoir operation. So the firm capacity of the Cushman project is 101-119 Mw, almost as high as the installed capacity.[80]

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then prorated Henwood's 1996 and 1997 figures to produce interpolated values for the years ending 8/97 and 9/97.

[76] Henwood, p. 19.

[77] Table 1, column 8; Table 2, column 8; Table 5, column 7; Table 6, columns 2 and 7.

[78] Summary Table, column 5. See also Table 6, column 7.

[79] Average capacity computed as 354 gwh/year divided by 8766 hours per year. Installed capacity per FEIS, p. xv.

[80] 101 Mw per FEIS, p. 5-2, consisting of 35 Mw at powerhouse 1 and 66 Mw at powerhouse 2 (John McEachern, FERC, 9/97, via e-mail). 119 Mw per Pacific

The Henwood report calculates annual capacity values based on the marginal cost to construct a new combined cycle plant and the regional surplus in the western grid.[81] However, using Henwood's capacity values in addition to its energy values gives a combined value for Cushman output that seems unreasonably high. In addition, there is a conceptual problem with doing so. Under perfect competition, if marginal generation determines energy value, then that will drive market price without regard to the cost to construct of any particular generator. New combined cycles will have to recover their capital costs from operating profits based on the difference between the system marginal energy cost and the (presumably lower, due to efficiency improvements) energy cost of the newly built plant. They will not get a specific payment for capacity. Alternatively, if they have a sale contract that does give them a specific payment for capacity, such a payment will be in exchange for a below-market energy payment to reflect the efficiency of the new unit. Buyers are unlikely to want to pay for the capital costs of new units **and** the energy costs of old units.

Based on the forgoing theoretical considerations, I have not included any value for capacity in my analysis. Capacity values are assumed to be captured in the energy values, which reflect both on-peak and off-peak prices.

A zero value for capacity is of course a lower bound assumption. Actual capacity values can only be higher. In the actual world, contracts exist and are still being signed in which payment is partially for capacity and not entirely for energy. I therefore tried to assess whether the non-firm COB prices which I used to benchmark the Henwood energy values are themselves reflective of the full value of energy, or whether they are too low because they exclude capacity values which are being recovered elsewhere. For the four months ending 9/97, data were available on a near-daily basis for on-peak prices at COB for both firm and nonfirm energy. Since firm energy means energy whose availability is assured, and non-firm energy means energy which the seller has the right to curtail, the difference between the two should represent the value of capacity. The daily data show that the average premium for firm energy has been about $1 per Mwh for the last four months, or about 5 percent above the price of nonfirm on-peak energy. Over the same period, on-peak nonfirm prices have averaged some $7.40/kwh higher than off-peak non-firm prices. The data suggests that the great majority of what is traditionally termed capacity value is being captured in the premium for on-peak energy, and that "firmness" only adds about another $1/Mwh. At Cushman, about 75 percent of

Northwest Coordination Agreement, consisting of 30.8 Mw at powerhouse 1 and 88 Mw at powerhouse 2 (TCL, 9/97, telephone conversation).

[81] Henwood, p. 25.

the generation is firm and the other quarter is nonfirm.[82] To the extent firm prices are about 5 percent higher than non-firm prices, ignoring capacity values will tend to understate the value of Cushman generation by something under 4 percent. I have examined the result of assuming an average generation value 4 percent higher than the one I actually used. The use of a 4 percent higher market value for generation reduces the required rate increase to pay for over-market cost of the EPA straw man proposal from 2.2 percent[83] to 2.1 percent. However, the required average rate increase to pay for increased costs compared to current Cushman costs increases from 3.8 percent[84] to 3.9 percent. Thus depending on whether one's point of comparison is current Cushman costs or costs with Cushman priced at market value (approximately Tacoma's proposal), accounting for firm/nonfirm cost differentials will improve or worsen the consequences of the EPA straw man proposal. But from either point of view, firm/nonfirm cost differentials do not significantly change the results presented here.[85]

d. Discount rate

It is an economic truism that a dollar in the future is not as valuable as a dollar today, both because of the effects of inflation and because a dollar today can be invested to produce more than a dollar in the future. The conversion factor used to convert future dollars back into an equivalent smaller number of present dollars is known as the discount rate. There is no accepted basis for determining an appropriate discount rate. When two different sets of costs are being compared which have different patterns over time (e.g., small costs now and large costs later, versus large costs now nd small costs later), the choice of discount rate can change which stream of costs will appear to be the larger and which the smaller. Thus, discount rates have historically been an area of great controversy and dispute.

The FEIS uses a discount rate of 7 percent,[86] which seems very high when taken together with its assumed zero percent inflation rate. A typical basis for a

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[82] Clint Kalich, TCL, personal communication, 9/97.

[83] Summary Table, column 11.

[84] Table 7, column 13.

[85] Even with an energy price equal to that in the FEIS, which is about 19 percent higher than the one I have used, the required average retail rate increase over current costs increases only to 4.1 percent, while the required average retail rate increase over rates which reflect a market-priced Cushman drops to 1.9 percent.

[86] FEIS, p. 5-7.

discount rate assumption is the cost of money for the project for which the discount rate is being used. Thus, the Federal government borrows money at a cost of only 3.5 percent per year above inflation when it sells inflation-adjusted 10-year notes,[87] suggesting that if inflation is expected to be 3 percent then 6.5 percent would be an appropriate discount rate for a government project. For Tacoma, the average interest rate TPU pays on its existing debt is 6.5 percent per year.[88] In 1997 Tacoma sold long-term bonds with an effective interest rate of about 5.6 percent.[89] These figures suggest that an appropriate discount rate for Tacoma would be about 6 percent if inflation is being included in the analysis.

I have avoided using discount rates in my analysis. The bulk of my analysis has been done on a year-by-year basis, obviating the need to rely on discount rates in calculating key results. In addition, the principal cost streams being compared (Cushman cost and value) have similar patterns over time (fairly steady year-to-year growth, at rates near the general rate of inflation), so that changes in discount rate do not change the relative merits of different alternatives. This is true even between alternatives which involve different levels of capital expenditure for mitigation, because of the fact that Tacoma uses debt to finance its large capital investments.[90] Thus all costs tend to get spread across many years.[91] To net out the impacts of inflation, I have presented Summary Table results in terms of 1998 dollars.

[87] NY Times, 11/7/97, p. C22, showing current yield of 3.53 percent on the U.S. Treasury 10-year inflation-adjusted note.

[88] Tindall, FERC, 9/97, phone conversation.

[89] Tacoma, Bond Prospectus, 1/15/97.

[90] Tacoma, Bond Prospectus, 1/15/97.

[91] Tacoma has suggested that bond indenture requirements with regard to debt service coverage ratios could limit Tacoma's ability to finance Cushman capital investments with debt, requiring large early year rate increases to provide cash up front. A review of Tacoma's current and projected debt service ratios shows that they are well above the levels required by Tacoma's bond indentures and City Council. Indeed, Tacoma is currently planning to finance virtually all of its 1997-2000 capital expenditures out of cash flow rather than debt, with no rate increases through the year 2000 (Prospectus, 1/15/97). The phasing of mitigation costs over the first 6 years of the new license would provide a further buffer against any risk of nonfinancability of mitigation costs.

C. Cost of Cushman generation with and without mitigation

1. Capital-related costs

a. License term

I have assumed a 30 year term, the shortest license term FERC grants. This is a worst-case assumption, because a longer license term would allow capital costs to be spread over a longer period and reduce annual costs.

b. Capital recovery factor

Table 3 shows several sets of annual costs. Each of these cost streams relates to a different capital-related cost, either at the existing project or associated with the EPA straw man mitigation measures. In each case, a key element of the analysis is the conversion of a capital requirement in a given year into a revenue requirement that will be spread over many years. The key to this conversion is the capital recovery factor, or CRF, found in column 3 of Table 3.

The CRF identifies the annual fraction of a given capital investment during the new license period which must be recovered over each of the remaining years of the license. I have assumed that all new capital costs which are financed will have a debt cost of 5.6 percent per year, consistent with the highest cost debt in TPU's 1997 bond sale. I have also assumed that all capital costs are recovered over a 30-year term. The latter assumption results in higher costs than under Tacoma's current accounting and rate recovery practices.

TCL currently depreciates Cushman capital investments over on a 62-year schedule. This means that TCL's ratepayers are not yet deemed to have fully paid for Cushman investments made in any year since before the beginning of World War II, and is part of the reason why TCL shows unamortized sunk costs at Cushman of about $30 million.[92]

If TCL was to continue using a 62-year depreciation schedule for Cushman costs, it would only have to recover about half of its $30 million in sunk costs over the assumed 30-year term of a new license, and its annual costs would be lower. More importantly, it would need to recover less than half of the $56 million (in 1996 dollars) of mitigation-related capital investments that the EPA straw man

[92] TCL, 9/97, e-mailed spreadsheet showing Cushman capital investment and depreciation by year. The bulk of the $30 million in undepreciated sunk cost is due to capital investments of over $27 million at Cushman in the 1990s. Even with a 30 year depreciation schedule instead of a 62 year schedule, these investments would still be largely undepreciated today.

proposal calls for over the next six years,[93] since only 24-30 years would have passed (out of 62) by the end of the next license period.

c. Sunk costs

I have accepted TCL's figure of $30 million for its sunk costs as of mid-1997, and assumed full recovery (with interest) of those costs over the new license term. The $30 million appears to include at least $5 million in licensing administrative costs, TCL's costs for consultants, FEIS comments, litigation threats, etc. Over 90 percent of it reflects costs incurred since 1990.[94] The assumption of full recovery over the license term is, as discussed in the preceding section, a worst case assumption since TCL's own depreciation schedule would leave much of the $30 million still unrecovered 30 years from now.

I have assumed that the interest cost associated with sunk costs is the interest cost associated with TCL's existing debt. This is a valid initial assumption, but ignores the potential for reducing existing debt costs through bond defeasance or refundings such as those TCL has already executed in the last several years.[95] Since effective interest costs on existing fixed yield bonds cannot go up, but can (and have) gone down through defeasance and refunding, the use of a 6.5 percent per year cost of existing debt is probably too high.

d. Future capital costs at existing facilities

Tacoma can expect to incur ongoing capital costs at its existing Cushman facilities. Its current biennial budget includes $515,000 of such costs for three specific projects.[96] I have escalated the 1997-98 capital investment with inflation, and assumed half of the resultant costs are financed and half are expensed,

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[93] Table 11, row 20.

[94] TCL, 9/97, e-mailed spreadsheet showing annual capital costs and depreciation schedules.

[95] See Prospectus, 1/15/97, for a list of existing Tacoma debt issuances which have already been defeased.

[96] TPU, 1997-1998 Biennial Budget, p. 84. A fourth project, $500,000 for a Cushman 2 spillgate upgrade, is under study only, and no funds will be spent on capital additions until the Cushman mitigation requirements have been decided (TCL, 9/97 phone conversation). This project is assumed to eventually cost $2 million and is included in the description above of mitigation measures.

consistent with current TCL policy.[97]

e. BPA billing credit

TCL currently receives a billing credit from BPA equal to a little over $500,000 per year. The credit is based on past capital investments in Cushman efficiency upgrades, and because it is based on past capital investments I have included it as a capital-related item.

The credit amount is calculated as the product of deemed Cushman output increases of 11.7 gwh per year from the efficiency upgrades, times the difference between the levelized cost of the efficiency upgrades ($67/Mwh) and BPA's PF rate (currently about $22/Mwh).[98] TCL has forecast the credit amount through 9/2001.[99] I have assumed that BPA's PF rate escalates at the general rate of inflation after 2001, and calculated the billing credit from 2001 through 2025, when the credit expires.

f. Mitigation measures

Section III above, along with Table 11, describes the cost and timing of the capital expenses associated with the EPA straw man mitigation measures. As described in section IV.C.1.b., above, I have assumed that all mitigation capital expenditures will be recovered over a 30-year term.

2. <u>O&M costs</u>

a. Existing facilities

There are a variety of data sources describing the existing or forecasted O&M costs associated with the existing Cushman project.[100] These sources are not consistent. I have used the forecast values from the 1/15/97 bond prospectus, which are consistent with the historical EIA 412 data, use the same underlying inflation rate assumption as my analysis, and are higher than the 1997-98

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[97] Prospectus, 1/15/97.

[98] Clint Kalich, TCL, phone conversations, 9/97.

[99] TCL, e-mailed billing credit spreadsheet, 9/97.

[100] DEIS, p. 5-7; FEIS, p. 5-4; TCL, White Paper, 1/10/97, p. 6; Prospectus, 1/15/97, p. 45; EIA Form 412; TPU, 1997-1998 Biennial Budget, p. 76.

budget figures.

FERC assumes that under the JRP scenario Cushman 2 powerhouse will be basically unused, and adjusts its O&M costs downward accordingly.[101] My analysis shows that Cushman 2 will continue to generate (under average hydrological conditions) 31-89 gwh per year, versus 229 gwh at present.[102] This is a reduction of up to 87 percent, consistent with the flow reductions described above. I have assumed that Cushman 2 powerplant will still need to be maintained and operated, and have not reduced O&M costs commensurate with the EPA straw man flow reductions. This is presumably a worst-case assumption, since at least some O&M costs are probably generation-sensitive, and would be reduced if generation decreased up to 87 percent.

b. Mitigation measures

The O&M costs associated with the EPA straw man mitigation measures are identified above in Section III.

D. Results

Once the various assumptions regarding Cushman value and cost have been made, it is simple to calculate the net cost of Cushman relative to market value or relative to current cost. The net cost results in Tables 5 and 6 show that for each year of the license term the existing project would cost less than its market value, but the mitigated project would cost more. The Summary Table shows the same results when cost and values are expressed in terms of average 1998 dollars over the license term. In dollar terms, the existing project would have an average cost over a 30-year license term of $3.4 million per year (in 1998 dollars) less than the market value of its output, while Cushman with the EPA straw man mitigation conditions would have an average cost of $4.8 million more than the value of its output.[103] The cost of the EPA straw man proposal would be somewhat less than that of the FERC staff proposal in terms of cost per Mwh.[104] The EPA straw man

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[101] FEIS, p. 5-5; John McEachern, FERC, 9/97 e-mail.

[102] Table 1, column 6. Table 2, column 6.

[103] Summary Table, column 8.

[104] $32.3/Mwh for EPA versus $36/Mwh for FERC staff. Summary Table, column 6. Both figures are in 1998 dollars, averaged over the license term. However, they are based on different values for market value (Summary Table, column 5), different inflation rate assumptions, and other differing assumptions which make them difficult

proposal would cost almost exactly the same as the FERC staff proposal for Cushman relative to market value.[105]

V. Rate impact of the EPA straw man proposal

Tacoma ratepayers do not pay for Cushman costs directly on their electric bills. Rather, Cushman costs are combined with all other TCL costs in developing retail rates. Those other costs the rest of TCL's power supply portfolio, plus an average of $17/Mwh for distribution and transmission, taxes, low income/conservation programs, and other costs.[106] I have taken the Cushman costs described above and combined them with estimates of the rest of the TCL system costs and loads. The result is an estimate of the increase in TCL retail rates which would be required to cover the increased Cushman costs associated with raising the cost of Cushman either to market price equivalence or to the level associated with the EPA straw man proposal.

A. Inputs and Assumptions

TCL has forecasted its sales through 2018 and its retail rate revenue through 2000.[107] I have extrapolated those forecasts to estimate future retail rates and revenues for TCL.[108] Rates decline slightly to the year 2000, then grow to $76/Mwh by the year 2027.[109] Average rates, in 1998 dollars, are just over $32 per Mwh. Revenues grow slightly faster than rates because of sales growth, increasing from $194 million in 1998 to $567 million in 2027.

I have assumed that the costs of Cushman mitigation are passed through on

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to compare directly.

[105] $4.8 million/year above market value for EPA versus $4.7 million/year for FERC staff. Summary Table, column 8. Both figures are in 1998 dollars, averaged over the license term, and both are relative to market value so as to account for their differing market values (Summary Table, column 5). However, they still have different inflation rate assumptions and other differing assumptions which make them difficult to compare directly.

[106] TPU, White Paper, 1/10/97, . 2.

[107] See Table 7, "sources" list.

[108] See Table 7, "sources" list.

[109] Table 7, column 3.

an equal percentage basis to all customers. This means that since residential rates are higher than industrial rates, the Cushman-related rate increase will be higher for residential customers (in $/Mwh) than for industrial customers.

B. Results

My results are shown both year-by-year (Table 7) and on an annual average basis in 1998 dollars (Table 7, Summary Table). The increase over current rates due to EPA straw man mitigation would average $8.2 million per year in 1998 dollars, or 3.8 percent over otherwise applicable rates.[110] The first $3.4 million per year of cost and 1.5% of average rate increase would result just from increasing Cushman costs to market levels, as Tacoma's Cushman proposal would do. A further cost averaging $4.8 million per year, requiring a further rate increase averaging 2.2 percent, would result from above-market Cushman costs due to the EPA straw man mitigation measures.

VI. Affordability of the EPA straw man proposal

EPA wants to know whether TCL can fund the EPA straw man mitigation measures.[111] The direct answer is yes, in the sense that the costs of the mitigation measures can be identified, and those costs incorporated into rates to be recovered from ratepayers. The real question is whether doing so would be practical in terms of the required rate design, the willingness of customers to pay the resultant rates, and the ability of customers to evade the resultant rates by finding alternative energy suppliers or reducing their load on the TCL system. This section and the next one address how much TCL can afford to charge customers for Cushman generation, how it could do so, and how it can avoid potential negative impacts ("bypass" and "death spiral") of increasing its rates.

A. The rate increase required to pay for the EPA straw man mitigation is relatively minor.

Table 8 shows that TCL is already a low-rate utility, and a rate increase averaging 3.8 percent would do nothing to change that.

B. TCL has options to reduce even the slight rate hikes which would otherwise result from the EPA straw man case.

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[110] Summary Table, columns 8 and 11. Table 7, column 13.

[111] Scope of work, task 4.

1. <u>City taxes</u>

TCL revenues are taxed by the City of Tacoma, so that electricity rates provide a revenue source to the City. The transfer of funds from TCL to the City costs TCL ratepayers about $14 million per year,[112] almost triple the above market cost of Cushman. So if retail rate pressures did exist, reducing the City tax would be another way to get to competitive rates. Reducing transfer payments from the municipal electric utility to the municipal general fund is currently being done or proposed in several California cities as a response to competitive market pressures.

2. <u>Steam plant #2</u>

TCL's steam plant #2 is another source of potential rate reductions. This facility had 1995 actual operating costs of $65 per Mwh, far above its market value, and even with forecasted improvements is still expected to cost $39 per Mwh in 1999-2000.[113] By continuing to operate steam plant #2, TCL is effectively providing a subsidy to Tacoma's refuse disposal service at the expense of its electrical customers. Imposition of a tipping fee to bring the net cost of steam plant #2 closer to market levels would provide a more accurate pricing signal to Tacoma's refuse disposal service, and would reduce the rate increase which might otherwise be necessary to pay for the costs resulting from the EPA straw mn proposal at Cushman.

3. <u>Debt refinancings</u>

Finally, debt refinancings are a potential source of rate reductions. When interest rates on new debt are lower than those on existing debt, Tacoma can (and has) refinanced its old debt to reduce its borrowing costs. While the long-term trend of interest rates is unknowable, the variation in interest rates over time makes it likely that there will be some periods in which debt refinancings are a viable means of reducing TCL's overall cost of providing electricity. Indeed, interest rates are currently lower than at the time of Tacoma's last debt refinancing, in January 1997.

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[112] Tacoma, Bond Prospectus, 1/15/97, p. 52. Projected gross earnings tax payments by TCL to Tacoma average $13.8 million per year in 1997-2000.

[113] Tacoma, Bond Prospectus, 1/15/97, pp. 43 (generation) and 45 (operating cost). Note that these are just operating costs, and do not include capital costs and sunk cost recovery, which would make the plant's economics look even worse.

C. The existence of above-market net costs, on paper, is itself a strong incentive to reduce costs and/or increase revenues, so that the potential stranded costs at Cushman may not actually be as severe as now anticipated

FERC, in the **Mead** decision, describes the difficulties of accurately projecting costs and values over a 30 year period. Generation owners have long had an incentive to poormouth their projects to FERC to obtain less onerous mitigation requirements. The risk of self-serving (or simply inaccurate) forecasts is one reason that FERC, post-**Mead**, no longer rejects mitigation packages simply because they would result in negative project economics. Numerous projects have been granted licenses by FERC or proposed for relicensing by FERC staff since **Mead** despite FERC economic analyses showing negative lifecycle economics.[114] Licensees accept such projects because either:

(1) they can in fact operate projects more economically than projected during relicensing, or

(2) the negative project economics associated with relicensing conditions are still preferable to the economic costs of rejecting the license (i.e., decommissioning).

In either of the above cases, accepting a license with conditions that will apparently result in stranded costs is preferable to rejecting mitigation conditions based solely on their forecasted impact on total project cost.

D. TCL can use stranded cost charges to recover above-market Cushman costs

1. The reality of above-market-cost resources

In Lake Wobegon, "all the children are above average." In an electric utility's perfect world, all its generation resource costs are below market. But in the real world, some children have to be below average and some projects have to be above market.

TCL already has several other resources priced above market levels. It buys an average of 225 gwh per year from the Grand Coulee Hydroelectric Power

[114] David Marcus, "FERC's economic analysis of hydro projects: A review of policy and practice since the Mead decision," 3/18/97, p. 19 and Appendix A. 37 of the 91 post-Mead economic analyses by FERC show negative net annual benefits for the mitigation alternative proposed by FERC staff or licensed by FERC.

Authority, at a projected cost this year of over $43 per Mwh.[115] It generates an average of 175 gwh per year at its Steam Plant No. 2, at a projected cost this year of over $34 per Mwh excluding debt service.[116] It generates an average of 648 gwh per year from its share of the Centralia coal project, at a projected cost this year of over $18 per Mwh excluding debt service, and with potential near-term capital addition costs of $18 million.[117] It buys over $14 million per year of electricity from BPA,[118] paying cost-based tariffs which include costs for the WPPSS 1 and 3 nuclear projects from which it gets no generation whatsoever, since those projects were abandoned during construction. Thus TCL operations confirm the fact that its supply portfolio can and will include some projects which are more expensive than others, and more expensive than current market prices.

At the national level, stranded costs are the rule rather than the exception. Much of the current drive for restructured electricity markets is rooted in the fact that existing projects are more expensive than new projects (in economists' jargon, average cost is above marginal cost). Regulators have almost universally accepted that marking projects down to market levels will result in otherwise unrecoverable above-market costs (the "stranded costs") and that special provisions need to be made to allow utilities to recover their prudently incurred stranded costs.[119] So the issue for TCL is not whether an above-market cost Cushman is possible, but how it can recover any above market costs at Cushman in the context of the emerging competitive market.

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[115] Tacoma, Bond Prospectus, 1/15/97, pp. 43-45.

[116] Tacoma, Bond Prospectus, 1/15/97, pp. 43-45. Actual costs in past years have been far higher.

[117] Tacoma, Bond Prospectus, 1/15/97, pp. 34, 43-45.

[118] Tacoma, Bond Prospectus, 1/15/97, p. 45. $14 million per year is the projected 1998-2000 cost of BPA purchases. Past purchases from BPA exceeded $50 million per year in 1991-94.

[119] Imprudent costs are universally excluded from rates when they are identified. The exclusion of imprudent costs from rates occurs whether or not they are above market costs, and in any case does not apply here since no one is suggesting that FERC-imposed license conditions would be imprudent costs.

As for allowance of stranded cost recovery, New Hampshire is the only state to date to reject the principal of allowing recovery in retail rates of stranded costs, and its attempt to exclude some stranded costs from rates is currently in litigation.

2. Structuring a "nonbypassable" charge - the California experience

California is now nearing the end of a three-plus year period of planning for the simultaneous introduction of retail competition and recovery of above-market utility generation costs. The key element in doing so is the "competition transition charge," or "CTC." The CTC represents the component of rates which collects the above-market costs of generation. However, while it is calculated based on generation costs and value,it is not part of the unbundled generation component of ratepayers bills. Most importantly, if a customer shifts to a new supplier for generation, that customer continues to pay the CTC to its former generation supplier. The CTC charge is thus "nonbypassable." Everybody pays it. Shopping for a new generation supplier is still allowed and encouraged, but price competition among new suppliers is based on their generation portfolios, not their CTC charges.

At the wholesale level, FERC has limited stranded cost recovery to above-market costs incurred prior to the issuance of Order 888. The idea is that generation owners should not be allowed to incur new above market costs and then recover them from their customers. No such limit exists at the retail level. In California, for example, the above-market component of contract purchase costs from Qualifying Facilities (QFs) will continue to be collected in CTC for as long as the contracts continue in force, in some cases for 20 years. PG&E has also specifically requested that not-yet-incurred relicensing and mitigation costs of over $100 million be included in its CTC charge. There is a clear precedent for TCL to do likewise and recover its Cushman above-market costs, if any, from ratepayers through a nonbypassable CTC component of rates rather than through the generation component which is quickly becoming subject to competition.

3. Rate design to avoid loss of customers

Unbundling electric rates into separate components and making the CTC component nonbypassable eliminates the risk that alternative generation suppliers will compete on the basis of who has the lowest CTC. But it does nothing about the risk that customers will physically leave, or implement conservation measures to reduce their bills, in order to avoid some (with conservation) or all (by leaving) of the rate. Customer loss can be mitigated through two different kinds of rate design measures.

First, CTC costs can be included in nonvariable components of rates to the extent possible. For example, TCL's current residential rate consists of a $5.50 per month fixed charge plus 3.99 cents per kwh consumed. The estimated rate increase required by the EPA mitigation conditions would equate to about $1 per month in

1998-2000 for a TCL residential customer using 1000 kwh per month.[120] That $1 per month could be collected either by increasing the fixed component of residential rates (from $5.50 per month to $6.50) or by increasing the variable component (from 3.99 cents per kwh to 4.09 cents per kwh). Assigning the increase to the variable portion would increase incentives for conservation, and might then require a further rate increase to recover revenues lost due to increased conservation. Assigning the rate increase to the fixed charge would leave conservation incentives unchanged. By taking the different impacts of rate structure into account, TCL could minimize the sales-dampening impacts of CTC charges.

In any event, this is not likely to be too serious a problem. The rate increases required by Cushman mitigation are small. TCL does not even have an estimate of its customer's price elasticity,[121] suggesting the problem is more theoretical than a serious concern. In the period 1979-86, TCL residential rates rose over 12 percent per year, yet residential sales rose as well. During the same period, large industrial sales to "CP" customers rose 28 percent while rates were going up over 14 percent per year. Clearly, small percentage increases in rates associated with Cushman are not going to trigger a "death spiral."

Second, CTC charges can include a departure charge for customers who completely leave the system. In particular, not-yet-depreciated sunk costs (which are about $30 million for Cushman) are candidates for recovery through departure charges. Someone who has used TCL generation for many years, and now leaves the TCL system because they don't want to pay for the environmental mitigation costs of Cushman, should not thereby be allowed to also escape paying for the sunk costs at Cushman which were incurred while they were a TCL customer.

4. Stranded cost recovery can be done over a multi-year period to reduce immediate rate impacts, if desired.

Traditional rates usually make some attempt to recover capital costs over a period linked to the life of the investment. Stranded costs, in contrast, have no intrinsic recovery term. CTC can be set high, for a short period, in order to accelerate recovery of stranded above-market costs and "clear the decks" for pure market costs. That is being done in California, where nuclear and fossil generation costs which would historically have been collected over the next two decades will

[120] Table 7, column 15. These figures assume the Cushman-related rate increase is assigned to different customer classes as a constant percentage increase in the revenue requirements for each class. If Cushman-related increases are assigned to customer classes on the same dollars per Mwh basis for all classes, the impact on residential ratepayers would be smaller by about 15 percent (Table 7, ratio of columns 12 and 14).

[121] Clint Kalich, TCL, 9/97, phone conversation.

instead be collected in CTC over a four-year period. Or CTC can be set low to collect stranded costs over a longer period and avoid the rate shock potentially associated with accelerated recovery of stranded costs. That is also being done in California, for residential and small commercial customers, where a 1998-2001 rate decrease of ten per cent is being implemented at the expense to those customers of higher rates in 2002-2007.

Fast CTC recovery has two advantages. It reduces financing charges, and it shortens the time period over which the potential for bypass will exist. The point is, the choice will be up to TCL.

5. Quantitative estimate of the required stranded cost charges for the EPA straw man mitigation case

The discussion above identifies how TCL can pay for above market Cushman costs (through stranded cost charges to its customers), how it can structure those charges to avoid bypass (by unbundling them from generation and assessing them against all customers) or a death spiral (by collecting as much of the stranded cost as possible in nonvariable rates), and why it might want to do so (avoidance of decommissioning costs; opportunities to reduce actual costs below projected costs). Given the actual size of Cushman-related stranded costs, much of that discussion is unnecessary. The required increase in average TCL retail rates to pay for above-market Cushman costs, with the EPA mitigation conditions, is about 2.2 percent,[122] and will leave TCL with some of the lowest rates in the United States.

[122] Summary table, column 11, "EPA straw man proposal" row.

Appendix 1

Glossary

Cost: The dollars which must be spent to obtain the thing (e.g., kwh from a powerplant) whose cost is being reported. Note that the cost and value of a thing are often different.

Direct Access: Allowing retail customers to contract directly with generation suppliers other than the local utility to whom they are physically interconnected.

Rates: The unit charges for electricity paid by customers. Rates are expressed in terms of dollars per unit (e.g., \$/kwh or \$/Mw-month).

Retail: Involving customers who are purchasing for their own use, rather than for resale.

Stranded cost: The portion of the cost of electricity from a given source which is in excess of the value of the electricity; or, the portion of the capital cost of an electrical generation facility which is not recoverable via sales at market-based rates.

Value: The dollars for which the thing whose value is being reported (e.g., kwh from a powerplant) can be sold. Note that the cost and value of a thing are often different.

Wholesale: Involving customers who are purchasing in order to resell, rather than for their own use.

Appendix 2

Practicalities of stranded cost recovery

The main body of this report suggests that above-market costs of Cushman (or any other TCL generation resource, for that matter) could be collected via a nonbypassable stranded cost charge or CTC, unbundled from the generation component of rates which may be (and for TCL's "CP" customers, already is) subject to market price competition. This section deals with the mechanics of how stranded costs can be quantified and collected in rates.

I. Quantifying stranded costs

Stranded costs can be quantified over any time period desired: hourly, daily, monthly, or annually. The basic concept is that stranded costs are the above-market-value costs of a resource. Costs are identified in the same ways as they are in the present system of cost-based rates. They include the direct and indirect O&M costs of a project, plus amortization of any capital costs including sunk costs. The market value to which the cost is compared is the sum of the hourly market values of the project, consisting (for each hour) of the project output times the market price for that hour, including any price for ancillary services which the project is producing. Ancillary services are electrical products other than kwh, such as spinning reserve, which are now beginning to be priced and sold on a market basis.[123] Because both output and market price can vary hourly, stranded costs can vary hourly.

Measuring market price is a key element in determining stranded costs. In this report, the nonfirm energy price at COB has been used as a proxy for market price. The conceptually appropriate price for TCL to use would be TCL's hourly marginal cost, the price at which TCL could either buy another kwh of generation if it was buying and needed to buy more, or sell another kwh of generation if it was selling and wanted to sell more.[124] Hourly marginal cost, commonly known as

[123] FERC Orders 888 and 888A define specific ancillary services, as does the pending California Independent System Operator (ISO) tariff.

[124] If TCL is only participating in the market as a buyer or seller in a given hour, then it should use the marginal value of whichever activity it is doing. The two measures of marginal cost, technically known as the incremental marginal cost and decremental marginal cost, should be equal any time TCL is both buying and selling. If the marginal cost to buy is more than the marginal revenue from selling, TCL can save money by reducing both its purchases and sales. If the marginal cost to buy is less than the marginal revenue from selling, TCL can

"system lambda," is routinely tracked by most utilities.[125] For TCL, the COB price or some similar PNW wholesale energy price may well be its marginal cost in most hours.

Once project cost and market price have been determined, the difference between them represents stranded costs. However, since rates are generally set in advance and the methodology described here only reveals stranded costs on a **post hoc** basis, based on actual costs and actual market prices, some method is still needed to collect stranded costs and remedy any imbalances between forecasted stranded costs and actual stranded costs.

II. Putting stranded cost recovery into rates - California model

A. Use forecasted values with a true-up to actuals

The California approach to stranded cost recovery is based on the use of estimates to quantify costs, generation quantities, and market value in advance, with an after-the-fact true up to reflect actual stranded costs. Because a true-up is part of the process, initial forecasts do not have to be more than roughly accurate, and do not need to be intensely litigated. For example, the market price of electricity in the California process will be determined by the Power Exchange (PX) price,[126] which varies hourly and is not known more than one day ahead. Yet all parties quickly agreed on a 1998 average PX price to use to forecast CTC costs, with no litigation at all.[127]

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make money by increasing both its purchases and sales. If TCL is neither buying nor selling, then it can still determine its marginal value of energy from the marginal operating cost of its most expensive resource that it is operating.

[125] TCL has indicated that it does not track its hourly marginal cost at present (Clint Kalich, 9/97, telephone conversation). Whether this is true or not, TCL will certainly want to know and monitor its hourly marginal costs as it enters the era of competitive generation.

[126] The three large California investor-owned utilities (IOUs) are required by law to purchase 100 percent of their energy requirements from the PX in the early years of restructuring. The PX will be an auction market for wholesale electricity sales. As such, the PX prices unambiguously represent the IOUs' marginal costs.

[127] The agreed-upon price happens to be over $24 per Mwh, well above the market price for 1998 used in this report. However, the whole point of the PX price forecast

B. Accelerate recovery of sunk costs

On the cost side of the ledger, the California approach to stranded cost rates is characterized by the acceleration of sunk costs. By charging ratepayers more than they would have paid under traditional cost-based ratemaking,[128] the California utilities are collecting "excess" revenues which are being used to quickly pay off all sunk generation costs. The advantage of doing so is that capital costs are sharply reduced, just as they are when a home mortgage is paid off in less than the standard 30 years. Once sunk costs are fully amortized rates will drop sharply.

In the case of Cushman mitigation, for example, the EPA straw man mitigation measures have a combined capital cost of $56.5 million in 1996 dollars,[129] or $65.4 million in as-spent dollars. Yet the revenue requirements associated with those measures will total some $135.8 million.[130] The difference between $65.4 million and $135.8 million represents $70.4 million in interest costs which could be substantially reduced through accelerated cost recovery.

C. Trade rate certainty for duration uncertainty

One of the most striking features of the California approach to stranded cost recovery is its use of a rate freeze. Total rates have been set in advance for a multi-year period. This provides customers with a level of certainty. However, total rates also include a component for market-priced generation, whose cost is unknown in advance. The way uncertainty in generation cost is balance with certainty in total rates is by making the stranded cost component of rates (the CTC) vary inversely with generation costs. Thus, if total rates are 10 cents per kwh, and cost based components such as transmission, distribution and various minor components of rates add up to 3 cents per kwh, then 7 cents per kwh are left for generation and CTC. Then, if generation costs in the market in a given month are 2 cents per kwh, the other 5 cents are deemed to be CTC payments. But if market prices rise to 3 cents per kwh, then the CTC component falls to 4 cents per kwh.

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is that it is only a placeholder for ratemaking purposes, no party has endorsed its accuracy, and it does not need to be accurate.

[128] Various parties in California ratemaking proceedings have estimated that California rates would currently be about 10 percent lower if restructuring were not occurring and rates were based on traditional cost-of-service principles and depreciation schedules.

[129] Table 11, line 20.

[130] $65.4 million x 30 years x .0692/year capital recovery factor (Table 3, column 3).

Ratepayers see all the components on their unbundled bills, but the total is always constant.

The use of a fixed total bill with a varying stranded cost component means stranded cost collection varies over time. Thus, PG&E may collect $3 billion towards its stranded costs in one year, $4 billion in another, but only $2 billion in another if market prices for generation rise. This situation is feasible because the duration of stranded cost collection is not fixed in advance.[131] Only the methodology for quantifying and collecting stranded costs is predetermined, not the duration over which that methodology will need to be applied in order to reduce the stranded cost accounts to zero.

TCL could use a similar approach if it wished to. It could determine a rate level in excess of its forecasted costs, and then use the revenues collected under that rate in excess of its actual costs to pay down its sunk costs and other stranded costs. The term of such an above-cost rate need not be fixed in advance, though of course it could be estimated based on forecasted sales, costs, stranded costs, and market prices. The City of Pasadena in California is exploring such an option on a voluntary basis, with a near-term rate increase of over 20 percent to be used to accelerate recovery of sunk costs, followed in a few years by a rate decrease of over 30 percent.

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[131] A cut-off date for collecting stranded costs related to the sunk costs of utility generators has been set, but actual stranded cost collection will cease on the **earlier** of that date or the date when all applicable stranded costs have been collected. How much earlier will depend on future market prices and is completely unknown at this time.

Appendix 3

Impact of industrial direct access on TCL

I. TCL's largest customers now obtain energy supplies at a market price which is below TCL's average portfolio cost

TCL's five largest customers, its "CP" customers, all have unbundled rates under which they are charged separately for energy, transmission, and other system services. Effective October 1, 1997, all 5 CP customers will pay negotiated prices for the energy component of their service, prices which are based on market prices and are expected to be on the order of the prices estimated above for 1998 market prices (about $17 per Mwh).[132] Basically, TCL will go into the market and buy energy for these customers and pass it through to them at cost, through what is known as a "Non-Portfolio Power Service" tariff. All other customers will pay for energy based on the average cost of TCL's entire portfolio of energy resources, including both low cost (e.g., Cushman, at present) and high cost (e.g. Steam Plant No. 2) resources. For the CP customers, the Non-Portfolio Power Service tariff will save them millions of dollars per year compared to the former CP rate of approximately $23.60 per Mwh.[133]

II. This was a special situation made possible only because market prices were less than the CP rate, which in turn was less than TCL's marginal cost of BPA purchases.

Selling to CP customers at below portfolio cost would appear to mean that TCL is subsidizing those customers' rates, at the expense of other customers. In fact it is not, because of a unique set of factors.

TCL's 1996 portfolio of generation resources included BPA purchases with both a fixed and variable component. Pursuant to language in the BPA purchase contract, TCL was able to convince BPA that if certain of TCL's retail sales were considered nonfirm rather than firm, it would be able to reduce its purchases from BPA and reduce the fixed as well as the variable portion of the payment. Reducing fixed payments as well as variable payments would effectively save TCL $28 for

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[132] The actual prices are non-public, but there is virtually no doubt they are below $20 per Mwh.

[133] TCL, 7/15/96 memo to TPU Board and City of Tacoma Mayor and City Council from Mark Crisson, p. 2.

each Mwh less that it bought from BPA. BPA agreed, creating an opportunity for TCL to save $28 per Mwh reduction in its sales.

The CP customer loads which are served by Non-Portfolio Power Service are considered nonfirm loads for BPA contract purposes. Thus, each Mwh which is served on Non-Portfolio Power Service represents a savings to TCL of $28 in BPA purchased power costs, offset by a cost to TCL of $23.60 less revenue under the prior CP rate. TCL's new generation cost to serve Non-Portfolio Power Service Customers, and its revenue from doing so, are equal (at perhaps $17 per Mwh) and balance out. So the net impact on TCL is a savings of $4.40 per Mwh shifted. TCL has forecasted that it will save $2.9 million per year, starting 10/1/97, from the reduced BPA purchases made possible by the shift of CP loads to Non-Portfolio Power Service.[134]

TCL's ability to save both itself and its CP customers money flows from the fact that it is replacing $28/Mwh generation with approximately $17/Mwh generation, keeping $4.40 of the savings for itself, and passing the rest through to the CP customers. It may not be able to repeat this course of action. Future reductions in the fixed component of the BPA contract are not possible, and almost all of TCL's other high-cost resources appear to be similarly unavoidable.[135]

III. Cushman costs can be either charged to CP customers or not

The fact that CP customers are now getting much of their energy from a non-portfolio mix of resources which does not include Cushman does not determine whether or not those customers can be charged for Cushman mitigation costs. The Non-Portfolio Power Service tariff still requires customers to pay for "use of Tacoma's System" and specifically states that "Tacoma and its other (non-CP Contract) customers shall not bear any uncompensated cost, including stranded investment, arising from Tacoma's provision of Non-Portfolio Power Service...."[136] Thus, Tacoma could still include stranded costs associated with Cushman as part of the non-power charges to CP customers.

Alternatively, of course, TCL could waive its right to prevent the Non-Portfolio Power Service tariff from impacting the stranded costs charged to other customers, and collect all above-market Cushman costs only from non-CP customer

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[134] TCL, 7/15/96, p. 3. These savings will continue only until 2001, when the Tacoma-BPA contract expires.

[135] One possible exception is Tacoma's steam plant #2, as discussed in the main body of the report.

[136] TCL, Non-Portfolio Power Service Addendum, p. 4, section 8.

rates. Since CP customers represent about 20 percent of Tacoma's retail load,[137] doing so would increase other customers' share of stranded costs by 25 percent above the otherwise applicable level.

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[137] Tacoma, Bond Prospectus, 1/15/97, p. 21.

Summary table - all values in 1998 dollars, averaged across 30-year license term

(1)	(2) Generation Gwh	(3) Replacement Gwh	(4) Total gwh	(5) Average Value/Mwh	(6) Cost/Mwh	(7) Cost compared to market-priced purchases of total gwh $/Mwh	(8) Cost compared to market-priced purchases of total gwh $MM/yr	(9) TCL average retail rate ($/Mwh)	(10) Rate increase due to Cushman license conditions, compared to rates with Cushman at market price $/Mwh	(11) Rate increase due to Cushman license conditions, compared to rates with Cushman at market price Percent
Marcus, 11/97:										
Existing project	354	0	354	$18.8	$9.3	-$9.6	-$3.4	$32.3	-$0.5	-1.5%
Project at market price	NA	NA	354	$18.8	$18.8	$0.0	$0.0	$32.8	$0.0	0.0%
EPA straw man proposal	166	188	354	$18.8	$32.3	$13.5	$4.8	$33.5	$0.7	2.2%
FERC, 11/96:										
FEIS, existing project	343	0	343	$22.3	$12.5	-$9.8	-$3.4	NA	NA	NA
FEIS, TCL alternative	332	11	343	$22.3	$21.9	-$0.4	-$0.1	NA	NA	NA
FEIS, JRP alternative	203	140	343	$22.3	$76.9	$54.7	$18.7	NA	NA	NA
FEIS, FERC staff alternative	293	50	343	$22.3	$36.0	$13.7	$4.7	NA	NA	NA
FEIS, decommissioning	0	343	343	$22.3	$30.4	$8.1	$2.8	NA	NA	NA

Note: FEIS values all calculated from FEIS, Tables 5-1, 5-6. Replacement gwh assumed purchased at FEIS cost (from Table 5-6), with cost/Mwh based on total gwh rather than generation gwh as done in FEIS. 1996 dollar values in FEIS escalated to 1998 values at 3 percent per year.

Sources for Marcus values:

Column 2: Tables 2, Column 7; Table 5, Column 3
Column 3: Column 4 - Column 2
Column 4: Table 2, Column 7
Column 5: Table 6, Column 7
Column 6: Table 6, Column 13
Column 7: Column 6 - Column 5
Column 8: Column 4 * Column 7*.001
Column 9: Table 7, Columns 3, 8, and 12, netted of inflation and averaged over license term
Column 10: Differences between values in Column 9
Column 11: Column 10 divided by market price case value in Column 9

Table 1 - Quantity and value of Cushman generation with EPA straw man mitigation conditions of 11/6/97

General inflation rate = 3.0%
Energy and capacity values: from Henwood, adjusted for inflation rate differences
Cushman 2 gwh/cfs: 0.2919
Cushman 3 Mwh/cfs 96.33
N. Fk. native flows: 813 cfs

Year 1 = 1998
813 cfs per Tacoma 26-96 data
427 cfs in 1929-1930 water year

Cushman 2 Mw per FERC e-mail of 9/24/97 and FEIS
Cushman 1 Mw per PNCAgreement, as discused with TCL, 9/25/97 phone
Capacity value included in energy value - see on/off-peak analysis

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Year	Year	Cushman 1 gwh	Cushman 2 cfs	North Fork cfs	Cushman 2 gwh	Total gwh	Energy value ($/Mwh)	Capacity value ($/kw-yr)	Cushman 1 Mw	Cushman 2 Mw	Total project value ($1000s)	Total project value ($/Mwh)
1	1998	126	306	507	89	215	16.95	0.0	31	0	$3,642	16.95
2	1999	126	306	507	89	215	17.56	0.0	31	0	$3,772	17.56
3	2000	126	306	507	89	215	18.06	0.0	31	0	$3,880	18.06
4	2001	126	230	583	67	193	18.84	0.0	31	0	$3,631	18.84
5	2002	126	230	583	67	193	19.62	0.0	31	0	$3,781	19.62
6	2003	126	230	583	67	193	20.39	0.0	31	0	$3,929	20.39
7	2004	126	183	630	53	179	21.16	0.0	31	0	$3,786	21.16
8	2005	126	105	708	31	156	22.10	0.0	31	0	$3,452	22.10
9	2006	126	105	708	31	156	22.85	0.0	31	0	$3,569	22.85
10	2007	126	105	708	31	156	23.68	0.0	31	0	$3,699	23.68
11	2008	126	105	708	31	156	24.60	0.0	31	0	$3,842	24.60
12	2009	126	105	708	31	156	25.51	0.0	31	0	$3,984	25.51
13	2010	126	105	708	31	156	26.41	0.0	31	0	$4,125	26.41
14	2011	126	105	708	31	156	27.39	0.0	31	0	$4,278	27.39
15	2012	126	105	708	31	156	28.37	0.0	31	0	$4,430	28.37
16	2013	126	105	708	31	156	29.42	0.0	31	0	$4,595	29.42
17	2014	126	105	708	31	156	30.56	0.0	31	0	$4,772	30.56
18	2015	126	105	708	31	156	31.68	0.0	31	0	$4,947	31.68
19	2016	126	105	708	31	156	32.79	0.0	31	0	$5,121	32.79
20	2017	126	105	708	31	156	33.98	0.0	31	0	$5,307	33.98
21	2018	126	105	708	31	156	35.25	0.0	31	0	$5,505	35.25
22	2019	126	105	708	31	156	36.59	0.0	31	0	$5,714	36.59
23	2020	126	105	708	31	156	37.92	0.0	31	0	$5,922	37.92
24	2021	126	105	708	31	156	39.32	0.0	31	0	$6,141	39.32
25	2022	126	105	708	31	156	40.71	0.0	31	0	$6,358	40.71
26	2023	126	105	708	31	156	42.26	0.0	31	0	$6,600	42.26
27	2024	126	105	708	31	156	43.80	0.0	31	0	$6,840	43.80
28	2025	126	105	708	31	156	45.40	0.0	31	0	$7,090	45.40
29	2026	126	105	708	31	156	47.06	0.0	31	0	$7,350	47.06
30	2027	126	105	708	31	156	48.79	0.0	31	0	$7,619	48.79

Table 2 - Quantity and value of Cushman generation with existing conditions at Cushman (i.e., no new license conditions)

General inflation rate = 3.0%
Energy and capacity values; from Henwood, adjusted for inflation rate differences
Cushman 2 gwh/cfs: 0.2919
Cushman 3 Mwh/cfs 96.33
N. Fk. native flows: 813 cfs

Year 1 = 1998
813 cfs per Tacoma 26-96 data
427 cfs in 1929-1930 water year

Cushman 2 Mw per FERC e-mail of 9/24/97 and FEIS
Cushman 1 Mw per PNCAgreement, as discused with TCL, 9/25/97 phone
Capacity value included in energy value - see on/off-peak analysis in text

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Year	Year	Cushman 1 gwh	Cushman 2 cfs	North Fork cfs	Cushman 2 gwh	Total gwh	Energy value ($/Mwh)	Capacity value ($/kw-yr)	Cushman 1 Mw	Cushman 2 Mw	Total project value ($1000s)	Total project value ($/Mwh)
1	1998	126	783	30	229	354	17.0	0.0	31	66	$6,003	16.95
2	1999	126	783	30	229	354	17.6	0.0	31	66	$6,217	17.56
3	2000	126	783	30	229	354	18.1	0.0	31	66	$6,394	18.06
4	2001	126	783	30	229	354	18.8	0.0	31	66	$6,673	18.84
5	2002	126	783	30	229	354	19.6	0.0	31	66	$6,949	19.62
6	2003	126	783	30	229	354	20.4	0.0	31	66	$7,222	20.39
7	2004	126	783	30	229	354	21.2	0.0	31	66	$7,492	21.16
8	2005	126	783	30	229	354	22.1	0.0	31	66	$7,827	22.10
9	2006	126	783	30	229	354	22.8	0.0	31	66	$8,091	22.85
10	2007	126	783	30	229	354	23.7	0.0	31	66	$8,386	23.68
11	2008	126	783	30	229	354	24.6	0.0	31	66	$8,711	24.60
12	2009	126	783	30	229	354	25.5	0.0	31	66	$9,033	25.51
13	2010	126	783	30	229	354	26.4	0.0	31	66	$9,352	26.41
14	2011	126	783	30	229	354	27.4	0.0	31	66	$9,700	27.39
15	2012	126	783	30	229	354	28.4	0.0	31	66	$10,044	28.37
16	2013	126	783	30	229	354	29.4	0.0	31	66	$10,418	29.42
17	2014	126	783	30	229	354	30.6	0.0	31	66	$10,819	30.56
18	2015	126	783	30	229	354	31.7	0.0	31	66	$11,217	31.68
19	2016	126	783	30	229	354	32.8	0.0	31	66	$11,611	32.79
20	2017	126	783	30	229	354	34.0	0.0	31	66	$12,032	33.98
21	2018	126	783	30	229	354	35.2	0.0	31	66	$12,481	35.25
22	2019	126	783	30	229	354	36.6	0.0	31	66	$12,956	36.59
23	2020	126	783	30	229	354	37.9	0.0	31	66	$13,427	37.92
24	2021	126	783	30	229	354	39.3	0.0	31	66	$13,924	39.32
25	2022	126	783	30	229	354	40.7	0.0	31	66	$14,416	40.71
26	2023	126	783	30	229	354	42.3	0.0	31	66	$14,965	42.26
27	2024	126	783	30	229	354	43.8	0.0	31	66	$15,508	43.80
28	2025	126	783	30	229	354	45.4	0.0	31	66	$16,076	45.40
29	2026	126	783	30	229	354	47.1	0.0	31	66	$16,665	47.06
30	2027	126	783	30	229	354	48.8	0.0	31	66	$17,276	48.79

Table 3 - Annual capital-related costs of Cushman project

Data inputs:

Sunk capital cost: $30 million per 1/15/97 White Paper
Share of sunk cost to be recovered over license term: 100 (30-yr depreciation versus Tacoma's 62)
License term: 30 years
TPU embedded cost of capital: 6.5% per Tindall, FERC , w/ semi-annual interest, => capital recovery factor = 0.07618
TPU marginal (incremental) cost of new capital: 5.6% per 1/97 prospectus, rounded up for issuance costs in years 1 a
Inflation 3.0% per year
Capital and O&M costs of mitigation measures: 9/19/97 Masonis memo; 9/22/97 conference call; Bregar, 9/26 and 11/7 phone; final revisions per Bregar memo, 11/6/97
O&M costs of existing project: 1/97 bond prospectus to 2000, then general inflation rate (no reduction due to reduced use of Cushman 2)
Capital additions to existing project: $515K in 1997-98 from Biennial Budget as discussed with TPU, 9/23/97; then escalate at general inflation rate
BPA billing credit: Per spreadsheet and phone call from TPU, 9/25/97 through 2001, then changed based on assumed increase in BPA PF rate equal to inflation

		<========= Existing project costs				=================>	<=====Future project costs associated with EPA straw man proposal =====>							
(1)	(2)	(3)	(4)	(5)	(6	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Year	Year	CRF for remaining license term (incremental)	Capital (50% expensed) (50/50 per Prospectus)	Capital (50% financed)	Sunk capita recovery	BPA billing credit	Shellfish	Wildlife	Recreation	Spillgate	Flood control, gage McTaggert Cr., other	Fish	Reduced BPA billing credit	Total capital-related costs
1	1998	0.0692	$129	$9	$2,285	-$525		$595		$147	$17	$4	$226	$2,887
2	1999	0.0692	$133	$18	$2,285	-$529	$91	$1,207	$36	$147	$17	$277	$228	$3,909
3	2000	0.0692	$137	$28	$2,285	-$534	$91	$1,838	$73	$147	$17	$687	$230	$4,997
4	2001	0.0692	$141	$37	$2,285	-$536	$91	$2,488	$111	$147	$17	$1,109	$268	$6,156
5	2002	0.0692	$145	$47	$2,285	-$529	$91	$2,488	$111	$147	$17	$1,109	$264	$6,174
6	2003	0.0692	$149	$58	$2,285	-$521	$91	$2,488	$111	$147	$442	$1,109	$260	$6,618
7	2004	0.0692	$154	$68	$2,285	-$513	$91	$2,488	$111	$147	$442	$1,109	$278	$6,659
8	2005	0.0692	$158	$79	$2,285	-$505	$91	$2,488	$111	$147	$442	$1,109	$309	$6,714
9	2006	0.0692	$163	$91	$2,285	-$497	$91	$2,488	$111	$147	$442	$1,109	$304	$6,733
10	2007	0.0692	$168	$102	$2,285	-$488	$91	$2,488	$111	$147	$449	$1,109	$299	$6,760
11	2008	0.0692	$173	$114	$2,285	-$479	$91	$2,488	$111	$147	$449	$1,109	$293	$6,781
12	2009	0.0692	$178	$126	$2,285	-$470	$91	$2,488	$111	$147	$449	$1,109	$288	$6,802
13	2010	0.0692	$184	$139	$2,285	-$460	$91	$2,488	$111	$147	$449	$1,109	$282	$6,824
14	2011	0.0692	$189	$152	$2,285	-$451	$91	$2,488	$111	$147	$449	$1,109	$276	$6,846
15	2012	0.0692	$195	$166	$2,285	-$441	$91	$2,488	$111	$147	$449	$1,109	$270	$6,869
16	2013	0.0692	$201	$180	$2,285	-$430	$91	$2,488	$111	$147	$449	$1,109	$263	$6,893
17	2014	0.0692	$207	$194	$2,285	-$420	$91	$2,488	$111	$147	$449	$1,109	$257	$6,917
18	2015	0.0692	$213	$209	$2,285	-$409	$91	$2,488	$111	$147	$449	$1,109	$250	$6,942
19	2016	0.0692	$219	$224	$2,285	-$397	$91	$2,488	$111	$147	$449	$1,109	$243	$6,968
20	2017	0.0692	$226	$239	$2,285	-$386	$91	$2,488	$111	$147	$449	$1,109	$236	$6,995
21	2018	0.0692	$233	$255	$2,285	-$374	$91	$2,488	$111	$147	$449	$1,109	$229	$7,023
22	2019	0.0692	$240	$272	$2,285	-$362	$91	$2,488	$111	$147	$449	$1,109	$221	$7,051
23	2020	0.0692	$247	$289	$2,285	-$349	$91	$2,488	$111	$147	$449	$1,109	$213	$7,080
24	2021	0.0692	$254	$307	$2,285	-$336	$91	$2,488	$111	$147	$449	$1,109	$205	$7,110
25	2022	0.0692	$262	$325	$2,285	-$322	$91	$2,488	$111	$147	$449	$1,109	$197	$7,141
26	2023	0.0692	$270	$343	$2,285	-$308	$91	$2,488	$111	$147	$449	$1,109	$189	$7,173
27	2024	0.0692	$278	$363	$2,285	-$294	$91	$2,488	$111	$147	$449	$1,109	$180	$7,206
28	2025	0.0692	$286	$382	$2,285	-$279	$91	$2,488	$111	$147	$449	$1,109	$171	$7,240
29	2026	0.0692	$295	$403	$2,285	$0	$91	$2,488	$111	$147	$449	$1,109	$0	$7,377
30	2027	0.0692	$303	$424	$2,285	$0	$91	$2,488	$111	$147	$449	$1,109	$0	$7,407

Table 4 - computation of annual total Cushman project costs with EPA straw man proposal

Data inputs:

Inflation: 3.0% per year
Capital and O&M costs of mitigation measures: 9/19/97 Masonis memo; 9/22/97 conference call; 9/26 and 11/7/97 Bregar phone; 11/6/97 Bregar memo
O&M costs of existing project: 1/97 bond prospectus to 2000, then general inflation rate (no reduction due to reduced use of Cushman 2)
Capital-related costs: Table 3
Replacement energy costs: difference between column 12 values in Tables 1 and 2

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Year	Year	Capital-related costs	Power plant O&M	<=====Mitigation-related O&M				=====>	Total Cushman-related costs other than replacement energy	<=====Mitigation-related costs			=====>	Existing project costs ($1000s)
				Shellfish	Wildlife	Recreation	Fish	Other		Capital	O&M	Purchased replacement energy	Total ($1000s)	
1	1998	$2,887	$1,790				$104	$136	$4,916	$969	$240	$2,360	$3,589	$3,688
2	1999	$3,909	$1,847		$121		$653	$140	$6,670	$2,002	$914	$2,445	$5,360	$3,754
3	2000	$4,997	$1,908	$0	$249	$73	$673	$144	$8,044	$3,081	$1,139	$2,514	$6,735	$3,824
4	2001	$6,158	$1,965	$0	$385	$150	$693	$149	$9,498	$4,229	$1,378	$3,042	$8,648	$3,892
5	2002	$6,174	$2,024	$0	$529	$232	$1,251	$153	$10,363	$4,226	$2,165	$3,168	$9,558	$3,973
6	2003	$6,618	$2,085	$0	$545	$239	$1,288	$158	$10,933	$4,647	$2,229	$3,292	$10,169	$4,058
7	2004	$6,659	$2,147	$0	$561	$246	$1,327	$162	$11,103	$4,665	$2,296	$3,706	$10,667	$4,142
8	2005	$6,714	$2,212	$0	$578	$253	$1,367	$167	$11,291	$4,686	$2,365	$4,375	$11,436	$4,230
9	2006	$6,733	$2,278	$0	$595	$261	$1,408	$172	$11,446	$4,691	$2,436	$4,522	$11,650	$4,321
10	2007	$6,760	$2,347	$0	$613	$269	$1,450	$177	$11,616	$4,693	$2,509	$4,687	$11,890	$4,414
11	2008	$6,781	$2,417	$0	$632	$277	$1,494	$183	$11,782	$4,687	$2,585	$4,869	$12,141	$4,510
12	2009	$6,802	$2,490	$0	$651	$285	$1,538	$188	$11,954	$4,682	$2,662	$5,049	$12,393	$4,610
13	2010	$6,824	$2,564	$0	$670	$293	$1,585	$194	$12,130	$4,676	$2,742	$5,227	$12,645	$4,712
14	2011	$6,846	$2,641	$0	$690	$302	$1,632	$200	$12,311	$4,670	$2,824	$5,422	$12,916	$4,817
15	2012	$6,869	$2,720	$0	$711	$311	$1,681	$206	$12,498	$4,664	$2,909	$5,614	$13,187	$4,925
16	2013	$6,893	$2,802	$0	$732	$321	$1,732	$212	$12,691	$4,658	$2,996	$5,823	$13,477	$5,037
17	2014	$6,917	$2,886	$0	$754	$330	$1,783	$218	$12,889	$4,651	$3,086	$6,047	$13,785	$5,152
18	2015	$6,942	$2,973	$0	$777	$340	$1,837	$225	$13,094	$4,644	$3,179	$6,270	$14,093	$5,271
19	2016	$6,968	$3,062	$0	$800	$350	$1,892	$232	$13,304	$4,638	$3,274	$6,490	$14,401	$5,393
20	2017	$6,995	$3,154	$0	$824	$361	$1,949	$238	$13,521	$4,630	$3,372	$6,725	$14,728	$5,518
21	2018	$7,023	$3,248	$0	$849	$372	$2,007	$246	$13,744	$4,623	$3,473	$6,976	$15,073	$5,646
22	2019	$7,051	$3,346	$0	$874	$383	$2,068	$253	$13,974	$4,616	$3,578	$7,242	$15,435	$5,781
23	2020	$7,080	$3,446	$0	$901	$394	$2,130	$261	$14,211	$4,608	$3,685	$7,505	$15,798	$5,918
24	2021	$7,110	$3,549	$0	$928	$406	$2,193	$268	$14,455	$4,600	$3,796	$7,783	$16,178	$6,060
25	2022	$7,141	$3,656	$0	$955	$418	$2,259	$276	$14,707	$4,592	$3,909	$8,058	$16,559	$6,206
26	2023	$7,173	$3,766	$0	$984	$431	$2,327	$285	$14,965	$4,583	$4,027	$8,365	$16,974	$6,356
27	2024	$7,206	$3,879	$0	$1,014	$444	$2,397	$293	$15,232	$4,574	$4,148	$8,668	$17,390	$6,510
28	2025	$7,240	$3,995	$0	$1,044	$457	$2,469	$302	$15,507	$4,565	$4,272	$8,986	$17,823	$6,669
29	2026	$7,377	$4,115	$0	$1,075	$471	$2,543	$311	$15,892	$4,394	$4,400	$9,315	$18,109	$7,098
30	2027	$7,407	$4,238	$0	$1,108	$485	$2,619	$320	$16,177	$4,394	$4,532	$9,656	$18,583	$7,251

Table 5 - Net costs of EPA straw man proposal for Cushman project, before accounting for required replacement energy

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Year	Cushman Generation (Mwh)	Cost of generation at Cushman ($1000s)	Cost of generation at Cushman ($/Mwh)	Value of generation at Cushman ($1000s)	Value of generation at Cushman ($/Mwh)	Net cost of generation at Cushman, over market ($1000s)	Net cost of generation at Cushman, over market ($/Mwh)
1	1998	215	$4,916	$22.88	$3,642	$16.95	$1,274	$5.93
2	1999	215	$6,670	$31.04	$3,772	$17.56	$2,898	$13.49
3	2000	215	$8,044	$37.44	$3,880	$18.06	$4,165	$19.38
4	2001	193	$9,498	$49.30	$3,631	$18.84	$5,867	$30.45
5	2002	193	$10,363	$53.79	$3,781	$19.62	$6,582	$34.17
6	2003	193	$10,933	$56.75	$3,929	$20.39	$7,004	$36.35
7	2004	179	$11,103	$62.05	$3,786	$21.16	$7,317	$40.89
8	2005	156	$11,291	$72.30	$3,452	$22.10	$7,839	$50.20
9	2006	156	$11,448	$73.30	$3,569	$22.85	$7,879	$50.45
10	2007	156	$11,616	$74.38	$3,699	$23.68	$7,918	$50.70
11	2008	156	$11,782	$75.44	$3,842	$24.60	$7,940	$50.84
12	2009	156	$11,954	$76.54	$3,984	$25.51	$7,970	$51.03
13	2010	156	$12,130	$77.67	$4,125	$26.41	$8,005	$51.26
14	2011	156	$12,311	$78.83	$4,278	$27.39	$8,033	$51.44
15	2012	156	$12,498	$80.03	$4,430	$28.37	$8,068	$51.66
16	2013	156	$12,691	$81.26	$4,595	$29.42	$8,096	$51.84
17	2014	156	$12,889	$82.53	$4,772	$30.56	$8,118	$51.98
18	2015	156	$13,094	$83.84	$4,947	$31.68	$8,146	$52.16
19	2016	156	$13,304	$85.19	$5,121	$32.79	$8,183	$52.40
20	2017	156	$13,521	$86.58	$5,307	$33.98	$8,214	$52.60
21	2018	156	$13,744	$88.01	$5,505	$35.25	$8,240	$52.76
22	2019	156	$13,974	$89.48	$5,714	$36.59	$8,260	$52.89
23	2020	156	$14,211	$91.00	$5,922	$37.92	$8,289	$53.08
24	2021	156	$14,455	$92.56	$6,141	$39.32	$8,314	$53.23
25	2022	156	$14,707	$94.17	$6,358	$40.71	$8,348	$53.45
26	2023	156	$14,965	$95.83	$6,600	$42.26	$8,365	$53.56
27	2024	156	$15,232	$97.53	$6,840	$43.80	$8,392	$53.74
28	2025	156	$15,507	$99.29	$7,090	$45.40	$8,416	$53.89
29	2026	156	$15,892	$101.76	$7,350	$47.06	$8,542	$54.69
30	2027	156	$16,177	$103.59	$7,619	$48.79	$8,558	$54.80
Average, in 1998 $: (i.e., net of inflation)		166	$7,900	$47.46	$3,117	$18.72	$4,784	$28.74

Inflation assumption: 3.0% (below Henwood's 3.5, above market's 2.3 for 10-year note, equal to bond prospectus)
License assumption: 30 year term

Table 6 - Net cost of matching current output using EPA straw man proposal plus market purchases of replacement energy

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Replacement generation to match current total generation at Cushman			EPA straw man case, cost to match current Cushman generation		Value of current Cushman generation		Net cost of EPA straw man case, over market value of Cushman		Net cost of EPA straw man case, over cost of existing project		Net cost of existing project		Year	Year
Mwh	Cost													
	($/Mwh)	($1000s)	($1000s)	($/Mwh)	($1000s)	($/Mwh)	($1000s)	($/Mwh)	($1000s)	($/Mwh)	($1000s)	($/Mwh)		
139	$16.95	$2,360	$7,277	$20.55	$6,003	$16.95	$1,274	$3.60	$3,589	$10.14	$3,688	$10.41	1	1998
139	$17.56	$2,445	$9,115	$25.74	$6,217	$17.56	$2,898	$8.18	$5,360	$15.14	$3,754	$10.60	2	1999
139	$18.06	$2,514	$10,559	$29.82	$6,394	$18.06	$4,165	$11.76	$6,735	$19.02	$3,824	$10.80	3	2000
161	$18.84	$3,042	$12,540	$35.41	$6,673	$18.84	$5,867	$16.57	$8,648	$24.42	$3,892	$10.99	4	2001
161	$19.62	$3,168	$13,531	$38.21	$6,949	$19.62	$6,582	$18.59	$9,558	$26.99	$3,973	$11.22	5	2002
161	$20.39	$3,292	$14,225	$40.17	$7,222	$20.39	$7,004	$19.78	$10,169	$28.72	$4,056	$11.45	6	2003
175	$21.16	$3,706	$14,809	$41.82	$7,492	$21.16	$7,317	$20.66	$10,667	$30.13	$4,142	$11.70	7	2004
198	$22.10	$4,375	$15,666	$44.24	$7,827	$22.10	$7,839	$22.14	$11,436	$32.30	$4,230	$11.95	8	2005
198	$22.85	$4,522	$15,970	$45.10	$8,091	$22.85	$7,879	$22.25	$11,650	$32.90	$4,321	$12.20	9	2006
198	$23.68	$4,687	$16,304	$46.04	$8,386	$23.68	$7,918	$22.36	$11,890	$33.58	$4,414	$12.47	10	2007
198	$24.60	$4,869	$16,652	$47.03	$8,711	$24.60	$7,940	$22.42	$12,141	$34.29	$4,510	$12.74	11	2008
198	$25.51	$5,049	$17,003	$48.02	$9,033	$25.51	$7,970	$22.51	$12,393	$35.00	$4,610	$13.02	12	2009
198	$26.41	$5,227	$17,357	$49.02	$9,352	$26.41	$8,005	$22.61	$12,645	$35.71	$4,712	$13.31	13	2010
198	$27.39	$5,422	$17,733	$50.08	$9,700	$27.39	$8,033	$22.69	$12,916	$36.48	$4,817	$13.60	14	2011
198	$28.37	$5,614	$18,113	$51.15	$10,044	$28.37	$8,068	$22.79	$13,187	$37.24	$4,925	$13.91	15	2012
198	$29.42	$5,823	$18,514	$52.29	$10,418	$29.42	$8,096	$22.87	$13,477	$38.06	$5,037	$14.23	16	2013
198	$30.56	$6,047	$18,937	$53.48	$10,819	$30.56	$8,118	$22.92	$13,785	$38.93	$5,152	$14.55	17	2014
198	$31.68	$6,270	$19,364	$54.68	$11,217	$31.68	$8,146	$23.01	$14,093	$39.80	$5,271	$14.88	18	2015
198	$32.79	$6,490	$19,794	$55.90	$11,611	$32.79	$8,183	$23.11	$14,401	$40.67	$5,393	$15.23	19	2016
198	$33.98	$6,725	$20,246	$57.18	$12,032	$33.98	$8,214	$23.20	$14,728	$41.59	$5,518	$15.58	20	2017
198	$35.25	$6,976	$20,720	$58.52	$12,481	$35.25	$8,240	$23.27	$15,073	$42.57	$5,648	$15.95	21	2018
198	$36.59	$7,242	$21,216	$59.92	$12,956	$36.59	$8,260	$23.33	$15,435	$43.59	$5,781	$16.33	22	2019
198	$37.92	$7,505	$21,716	$61.33	$13,427	$37.92	$8,289	$23.41	$15,796	$44.61	$5,918	$16.71	23	2020
198	$39.32	$7,783	$22,238	$62.80	$13,924	$39.32	$8,314	$23.48	$16,178	$45.69	$6,060	$17.11	24	2021
198	$40.71	$8,058	$22,764	$64.29	$14,416	$40.71	$8,348	$23.58	$16,559	$46.76	$6,206	$17.53	25	2022
198	$42.26	$8,365	$23,330	$65.89	$14,965	$42.26	$8,365	$23.62	$16,974	$47.94	$6,356	$17.95	26	2023
198	$43.80	$8,668	$23,900	$67.50	$15,508	$43.80	$8,392	$23.70	$17,390	$49.11	$6,510	$18.39	27	2024
198	$45.40	$8,986	$24,492	$69.17	$16,076	$45.40	$8,416	$23.77	$17,823	$50.33	$6,669	$18.84	28	2025
198	$47.06	$9,315	$25,207	$71.19	$16,665	$47.06	$8,542	$24.12	$18,109	$51.14	$7,098	$20.04	29	2026
198	$48.79	$9,656	$25,833	$72.96	$17,276	$48.79	$8,558	$24.17	$18,583	$52.48	$7,251	$20.48	30	2027
188	$18.91	$3,549	$11,449	$32.33	$6,665	$18.82	$4,784	$13.51	$8,169	$23.07	$3,280	$9.26	Average, in 1998 $ (i.e., net of inflation)	

Table 7 - Rate impacts of EPA straw man proposal as compared to replacing Cushman with market-priced generation, and as compared to existing Cushman project costs

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		<======== Base Case ========>					Rate increase attributable to above-market costs at Cushman with EPA straw man proposal				Rate increase attributable to increase in costs at Cushman with EPA straw man proposal, compared to current costs			
Year	Year	Average rate ($/Mwh)	Revenue from retail sales ($MM)	Retail sales (gwh)	Below-market costs at existing Cushman (MM$)	Above-market costs at Cushman w/ EPA straw man proposal (MM$)	$/Mwh	Percent for average customer	$/month for residential customers using 1000 kwh/mo (with residential variable rate = 39.9/34.5 of system average rate, as in 1998)		$/Mwh	Percent for average customer	$/month for residential customers using 1000 kwh/mo (with residential variable rate = 39.9/34.5 of system average rate, as in 1998)	
1	1998	34.5	193.99	5622	$2.31	$1.27	$0.23	0.7	$0.26	$0.26	$0.64	1.9	$0.74	$0.74
2	1999	34.3	195.96	5716	$2.46	$2.90	$0.51	1.5	$0.59	$0.57	$0.94	2.7	$1.09	$1.05
3	2000	34.1	196.82	5766	$2.57	$4.16	$0.72	2.1	$0.83	$0.79	$1.17	3.4	$1.35	$1.27
4	2001	35.1	207.8	5917	$2.78	$5.87	$0.99	2.8	$1.15	$1.05	$1.46	4.2	$1.69	$1.55
5	2002	36.2	216.6	5988	$2.98	$6.58	$1.10	3.0	$1.27	$1.13	$1.60	4.4	$1.85	$1.64
6	2003	37.3	225.8	6061	$3.17	$7.00	$1.16	3.1	$1.34	$1.15	$1.68	4.5	$1.94	$1.67
7	2004	38.4	235.7	6142	$3.35	$7.32	$1.19	3.1	$1.38	$1.15	$1.74	4.5	$2.01	$1.68
8	2005	39.5	245.8	6221	$3.60	$7.84	$1.26	3.2	$1.46	$1.18	$1.84	4.7	$2.13	$1.73
9	2006	40.7	256.6	6303	$3.77	$7.88	$1.25	3.1	$1.45	$1.14	$1.85	4.5	$2.14	$1.69
10	2007	41.9	268.0	6391	$3.97	$7.92	$1.24	3.0	$1.43	$1.10	$1.86	4.4	$2.15	$1.65
11	2008	43.2	279.9	6479	$4.20	$7.94	$1.23	2.8	$1.42	$1.05	$1.87	4.3	$2.17	$1.61
12	2009	44.5	292.2	6568	$4.42	$7.97	$1.21	2.7	$1.40	$1.01	$1.89	4.2	$2.18	$1.58
13	2010	45.8	305.0	6655	$4.64	$8.01	$1.20	2.6	$1.39	$0.98	$1.90	4.1	$2.20	$1.54
14	2011	47.2	316.6	6707	$4.88	$8.03	$1.20	2.5	$1.39	$0.94	$1.93	4.1	$2.23	$1.52
15	2012	48.6	328.6	6758	$5.12	$8.07	$1.19	2.5	$1.38	$0.91	$1.95	4.0	$2.26	$1.49
16	2013	50.1	341.1	6812	$5.38	$8.10	$1.19	2.4	$1.37	$0.88	$1.98	4.0	$2.29	$1.47
17	2014	51.6	353.5	6853	$5.67	$8.12	$1.18	2.3	$1.37	$0.85	$2.01	3.9	$2.33	$1.45
18	2015	53.1	366.1	6892	$5.95	$8.15	$1.18	2.2	$1.37	$0.83	$2.04	3.8	$2.36	$1.43
19	2016	54.7	379.8	6940	$6.22	$8.18	$1.18	2.2	$1.36	$0.80	$2.06	3.8	$2.40	$1.41
20	2017	56.4	393.8	6987	$6.51	$8.21	$1.18	2.1	$1.36	$0.78	$2.11	3.7	$2.44	$1.39
21	2018	58.1	408.5	7036	$6.83	$8.24	$1.17	2.0	$1.35	$0.75	$2.14	3.7	$2.48	$1.37
22	2019	59.8	423.7	7085	$7.18	$8.26	$1.17	1.9	$1.35	$0.72	$2.18	3.6	$2.52	$1.35
23	2020	61.6	439.4	7135	$7.51	$8.29	$1.16	1.9	$1.34	$0.70	$2.21	3.6	$2.56	$1.34
24	2021	63.4	455.8	7185	$7.86	$8.31	$1.16	1.8	$1.34	$0.68	$2.25	3.5	$2.60	$1.32
25	2022	65.3	472.8	7235	$8.21	$8.35	$1.15	1.8	$1.33	$0.66	$2.29	3.5	$2.65	$1.30
26	2023	67.3	490.4	7286	$8.61	$8.37	$1.15	1.7	$1.33	$0.63	$2.33	3.5	$2.69	$1.29
27	2024	69.3	508.6	7337	$9.00	$8.39	$1.14	1.7	$1.32	$0.61	$2.37	3.4	$2.74	$1.27
28	2025	71.4	527.5	7389	$9.41	$8.42	$1.14	1.6	$1.32	$0.59	$2.41	3.4	$2.79	$1.26
29	2026	73.5	547.2	7441	$9.57	$8.54	$1.15	1.6	$1.33	$0.58	$2.43	3.3	$2.81	$1.23
30	2027	75.7	567.5	7493	$10.02	$8.56	$1.14	1.5	$1.32	$0.56	$2.48	3.3	$2.87	$1.22
Average							$1.10	2.2	$1.28	$0.84	$1.92	3.8	$2.22	$1.42
							nominal	nominal	nominal	1998 $	nominal	nominal	nominal	1998 $

Sources for rate data:

1998-2000: 1/97 Bond prospectus
2009. Lesser of TCL, 4/22/96 Land to Svoboda memo, versus general inflation from 2000 on
2001-2008: Log-linear interpolation between values for 2000 and 2009
2010+: Escalation at general rate of inflation

Sources for revenue data:

1998-2000: 1/97 Bond prospectus
2001+: Calculated as product of retail average rate times retail sales

Sources for sales data:

1998-2000: 1/97 bond prospectus
2001-2018: Load forecast spreadsheet supplied by TCL
2019+ Escalation at 2017-2018 rate from TCL-supplied spreadsheet

Table 8 - comparison of TCL rates to those of other utilities

Ranked in order of increasing residential rates

(1)	(2)	(3)	(4)	(5)	(6)
Utility	Average overall retail rate ($/Mwh)	Average residential rate ($/Mwh)	Average commercial rate ($/Mwh)	Average industrial rate ($/Mwh)	Data source
Seattle City Light		42.1			Seattle City Light Website, 9/23/97
Eugene Water & Elec Bd		43.8			EWEB Website, 9/23/97 - 1995 data
Tacoma City Light (TCL)	34.6	43.9	44.9	27.9	1/97 prospectus - 1997 forecast
TCL w/ EPA straw man cas	35.9	45.6	46.6	29.0	Equal percentage class increases of 3.8%, per Table 7, column 13
Washington Water Power	47.6	49.8	54.1	33.3	12/96 actual per Bear, Stearns
Snohomish PUD		50.2			Seattle City Light Website, 9/23/97
Idaho Power Company	37.1	50.7	37.8	24.4	12/96 actual per Bear, Stearns
Portland General Electric	53.3	60.5	53.6	38.2	12/96 actual per Bear, Stearns
Montana Power Company	52.0	61.1	55.1	41.4	12/96 actual per Bear, Stearns
Pacificorp	47.4	61.3	54.1	34.7	12/96 actual per Bear, Stearns
Puget Sound Power & Light	59.9	61.4	64.3	46.5	12/96 actual per Bear, Stearns
United States average	68.6	76.3	68.2	45.6	Year ending 6/96, per DOE, MER, 7/97
Average of 110 U.S. IOUs	71.6	88.6	78.2	47.9	12/96 actual per Bear, Stearns

Table 9 - On-peak/off-peak shaping of Cushman generation and its effect on project value

9/96 - 8/97 actuals

Non-firm COB prices On-peak	off-peak	Time-weighted price	Generation-weighted price	Total Cushman value at nonfirm prices ($1000s)	Month/year
17.06	13.91	16.01	16.08	$717	Sep-96
20.33	16.34	19.00	19.13	$1,020	Oct-96
26.39	20.51	24.43	24.59	$1,223	Nov-96
23.82	15.55	21.06	21.76	$397	Dec-96
17.52	8.58	14.54	14.55	$913	Jan-97
15.15	6.73	12.34	12.27	$645	Feb-97
13.41	8.77	11.86	12.04	$621	Mar-97
15.95	10.99	14.30	14.92	$551	Apr-97
19.98	8.87	16.28	17.60	$570	May-97
15.44	7.95	12.94	13.25	$351	Jun-97
16.33	9.08	13.91	14.45	$287	Jul-97
20.81	14.2	18.61	18.49	$285	Aug-97
18.52	11.79	16.27	16.34	$7,580	

Table 10 - Effect of monthly generation pattern and monthly variation in value on value of Cushman generation

41385	30382	23192	13379	15010	13674	12215	14501	37632	42047	51814	53403	348634	Mwh generated - 1981-97 data
11.9	8.7	6.7	3.8	4.3	3.9	3.5	4.2	10.8	12.1	14.9	15.3	100.0	Percentage of annual generation - 16 years' data
0.98	1.17	1.50	1.29	0.89	0.76	0.73	0.88	1.00	0.80	0.85	1.14		Price as percentage of annual time-weighted average of 9/96-8/97 actuals at COB
11.7	10.2	10.0	5.0	3.8	3.0	2.6	3.7	10.8	9.6	12.7	17.5	100.4	Percentage of annual dollar value; sum > 100 because generation occurs mostly in higher-value months
1	2	3	4	5	6	7	8	9	10	11	12		Month

Table 11 - EPA straw man mitigation measures

(1)	(2)	(3)	(4	(5	(6	(7)
Line number	Mitigation measure	4(e) Item #	10(j) item #	Capital cost and timing		O&M cost
				Cost (1996 $1000s)	Year(s) of capital expense	(1996 $1000s per year)
1	Modify #2 spillgate	4	7	2000	1	0
2	Fish passage past dams	6		9000	3-4	300
3	Fish habitat development projects	7	13	0		56
4	Fish stocking and supplementation	8	18	1526	3-4	150
5	Remove McTaggert Cr. diversion	9	10	66	1	0
6	Mainstem sediment transport/capacity	11		5000	6	0
7	Telemetered stream gages	5	8-9	120	1	0
8	Flow effectiveness studies	10		75	10	100
9	Transmission line ROW management	12	37	37	1	20
10	Curation facility for cultural resources	13		0		1
11	Cultural resources training program	14		5	1	7
12	George Adams Hatchery improvements		21	3600	2	500
13	Recreational improvements		38-43	1420	2-4	194
14	Shellfish culture and seeding		25-28	1200	2	0
15	Wildlife mitigation lands (private land)		32	32402	1-4	0
16	Restore riparian habitat in North Fork		31	61	1	0
17	Gravel augmentation		12	0		5
18	Fish population monitoring plan		17	0		37
19	Wildlife habitat improvement plan		33	0		443
20	Total			56512		1813

Notes:

Column 3 shows the 4(e) condition number, if applicable, from the 7/15/97 revised 4(e) conditions. 4(e) conditions 1-3 involve flow modifications and do not have any direct capital or O&M costs.

Column 4 shows the item number(s) in the FERC listing of 10(j) proposals (FEIS, 11/96, Table 6-3, pp. 6-27 to 6-37) which corresponds most closely to the particular mitigation measure in the EPA straw man proposal.

Column 6 shows the year of the new license term in which specific capital costs would be incurred. Year 1 is assumed to be 1998.

Column 5 and 7 costs are from EPA, fax of 11/6/97 and Bregar 11/7/97 phone conversation, and from Jeri Sawyer, NW Economics, e-mail and phone, 11/12/97.